ORAL ARGUMENT NOT YET SCHEDULED
Case No. 23-1207
(Consolidated with Nos. 23-1157 (lead), 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1208, 23-1209, and 23-1211)

United States Court of Appeals
For the District of Columbia Circuit

UNITED STATES STEEL CORPORATION.

***Petitioner*,**

v.

ENVIRONMENTAL PROTECTION AGENCY AND MICHAEL S. REGAN, ADMINISTRATOR, U.S. EPA,

***Respondents*.**

On Petition for Judicial Review of a Final Rule of the Environmental Protection Agency, 88 Fed. Reg. 36,654 (June 5, 2023)

MOTION FOR STAY

August 22, 2023

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CERTIFICATE AS TO PARTIES, RULINGS, AND RELATED CASES, AND CORPORATE DISCLSOURE STATEMENT

Pursuant to D.C. Circuit Rules 18(a)(4), 27, and 28(a)(1)(A), Petitioner United States Steel Corporation certifies as follows:

Parties, Intervenors, and *Amici* to this Case:

- Petitioner: United States Steel Corporation
- Respondents: United States Environmental Protection Agency; Michael S. Regan, U.S. EPA Administrator
- Proposed Intervenors: None at present
- Proposed *Amici*: The Chamber of Commerce of the United States of America

Ruling Under Review

Petitioner seeks review of a final rule promulgated by the Environmental Protection Agency titled Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) (Exhibit A).

Related Cases

D.C. Circuit

No. 23-1157, *Utah v. EPA*

Petitioners: State of Utah, by and through its Governor, Spencer J. Cox, and its Attorney General, Sean D. Reyes

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Intervenors: City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland;

State of New Jersey; State of New York; State of Wisconsin; Air Alliance Houston; Appalachian Mountain Club; Center for Biological Diversity; Chesapeake Bay Foundation; Citizens for Pennsylvania's Future; Clean Air Council; Clean Wisconsin; Downwinders at Risk; Environmental Defense Fund; Louisiana Environmental Action Network; Sierra Club; Southern Utah Wilderness Alliance; Utah Physicians for a Healthy Environment

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1181, *Kinder Morgan v. EPA*

Petitioner: Kinder Morgan, Inc.

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Intervenors: City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin;

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1183, *Ohio v. EPA*

Petitioners: State of Ohio; State of West Virginia; State of Indiana

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Intervenors: City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1190, *Am. Forest & Paper Assoc. v. EPA*

Petitioner: American Forest & Paper Association

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Intervenors: City of New York; Commonwealth of Massachusetts; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; State of New York; State of Wisconsin

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1191, *Midwest Ozone Group v. EPA*

Petitioner: Midwest Ozone Group

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-1193, *Interstate Natural Gas Assoc. of Am. v. EPA*

Petitioners: Interstate Natural Gas Association of America; American Petroleum Institute

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1195, *Assoc. Electric Coop., Inc. v. EPA*

Petitioners: Associated Electric Cooperative, Inc., Deseret Generation & Transmission Co-operative d/b/a Deseret Power Electric Cooperative; Ohio Valley Electric Corporation; Wabash Valley Power Association, Inc. d/b/a Wabash Valley Power Alliance; America's Power; National Rural Electric Cooperative Association; Portland Cement Association

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1199, *Nat'l Mining Assoc'n. v. EPA*

Petitioner: National Mining Association

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1200, *AISI v. EPA*

Petitioner: American Iron and Steel Institute

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1201, *Wisconsin v. EPA*

Petitioner: State of Wisconsin

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1202, *Enbridge (U.S.) Inc. v. EPA*

Petitioner: Enbridge (U.S.) Inc.

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1203, *Am. Chem. Council v. EPA*

Petitioners: American Chemistry Council; American Fuel & Petrochemical Manufacturers

Respondents: United States Environmental Protection Agency

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1205, *TransCanada Pipeline USA Ltd. v. EPA*

Petitioner: TransCanada Pipeline USA Ltd.

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1206, *Hybar LLC v. EPA*

Petitioner: Hybar LLC

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1208, *Union Elec. Co. v. EPA*

Petitioner: Union Electric Company, d/b/a Ameren Missouri

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1209, *Nevada v. EPA*

Petitioner: State of Nevada

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

No. 23-1211, *Arkansas League of Good Neighbors v. EPA*

Petitioner: Arkansas League of Good Neighbors

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Proposed *Amici Curiae*: Chamber of Commerce of the United States of America; Energy Infrastructure Council

Fifth Circuit

No. 23-60300, *Texas v. EPA*

Petitioners:

State of Texas; Texas Commission on Environmental Quality; Public Utility Commission of Texas; Railroad Commission of Texas; Association of Electric Companies of Texas; BCCA Appeal Group; Texas Chemical Council; Texas Oil & Gas Association; Luminant Generation Co., LLC; Coleto Creek Power, LLC; Ennis Power Co., LLC; Hays Energy, LLC; Midlothian Energy, LLC; Oak Grove Management Company, LLC; Wise County Power Company, LLC; State of Louisiana; Louisiana Department of Environmental Quality; State of Mississippi; Mississippi Department of Environmental Quality; Mississippi Power Company; Texas Lehigh Cement Company; Louisiana Public Service Commission; Energy Transfer, LP; Entergy Louisiana, LLC; Cleco Corporate Holdings, LLC; Louisiana Energy & Power Authority; Lafayette Consolidated Government / Lafayette Utilities System; NACCO Natural Resources Corporation; Mississippi Lignite Mining Company; Louisiana Chemical Association; Louisiana Mid-Continent Oil and Gas Association; Kinder Morgan, Inc.

Respondents:

United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Intervenors:

Air Alliance Houston; Clean Wisconsin; Downwinders at Risk; Louisiana Environmental Action Network; Sierra Club

Amici Curiae:

State of New York; State of Connecticut; State of Delaware; State of Illinois; State of Maryland; State of New Jersey; District of Columbia; Harris County, Texas

Sixth Circuit

No. 23-3605, *Kentucky Energy & Envt. Cabinet v. EPA*

Petitioner: Kentucky Energy and Environment Cabinet

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-3624, *Kentucky v. EPA*

Petitioner: Commonwealth of Kentucky

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-3641, *Energy Transfer LP v. EPA*

Petitioner: Energy Transfer LP

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-3647, *Buckeye Power, Inc. v. EPA*

Petitioners: Buckeye Power, Inc.; Ohio Valley Electric Corporation

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Seventh Circuit

No. 23-2510, *Energy Transfer LP v. EPA*

Petitioner: Energy Transfer LP

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-2511, *Energy Transfer LP v. EPA*

Petitioner: Energy Transfer LP

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Eighth Circuit

No. 23-2769, *Arkansas v. EPA*

Petitioners: State of Arkansas; Arkansas Department of Energy and the Environment, Division of Environmental Quality

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-2771, *Missouri v. EPA*

Petitioner: State of Missouri

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-2773, *Energy Transfer LP v. EPA*

Petitioner: Energy Transfer LP

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-2774, *Energy Transfer LP v. EPA*

Petitioner: Energy Transfer LP

Respondent: United States Environmental Protection Agency

Ninth Circuit

No. 23-1098, *Nevada Cement Co. v. EPA*

Petitioner: Nevada Cement Company

Respondent: United States Environmental Protection Agency

Tenth Circuit

No. 23-9551, *Tulsa Cement, LLC v. EPA*

Petitioner: Tulsa Cement LLC, d/b/a Central Plains Cement Company, LLC

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Amicus Curiae:

State of New York; State of Connecticut; State of Delaware; State of Illinois, State of Maryland; State of New Jersey; State of Wisconsin; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas

No. 23-9557, *PacfiCorp v. EPA*

Petitioners: PacifiCorp; Deseret Generation & Transmission Cooperative; Utah Municipal Power Agency; Utah Associated Municipal Power Systems

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Amicus Curiae:

State of New York; State of Connecticut; State of Delaware; State of Illinois, State of Maryland; State of New Jersey; State of Wisconsin; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas

No. 23-9561, *Oklahoma v. EPA*

Petitioners: State of Oklahoma; Oklahoma Department of Environmental Quality

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Amicus Curiae:

State of New York; State of Connecticut; State of Delaware; State of Illinois, State of Maryland; State of New Jersey; State of Wisconsin; Commonwealth of Pennsylvania; District of Columbia; Harris County, Texas

No. 23-9569, *Energy Transfer LP v. EPA*

Petitioners: Energy Transfer LP

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

Eleventh Circuit

No. 23-12528, *Alabama v. EPA*

Petitioners: State of Alabama; Attorney General, State of Alabama; Alabama Department of Environmental Management

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

No. 23-12531, *Alabama Power Co. v. EPA*

Petitioners: Alabama Power Company, Powersouth Energy Cooperative

Respondents: United States Environmental Protection Agency; Michael S. Regan, Administrator, U.S. EPA

RULE 26.1 DISCLOSURE STATEMENT

Pursuant to Fed. R. App. P. 26.1 and D.C. Circuit Rule 26.1, Petitioner United States Steel Corporation states:

United States Steel Corporation is organized under the laws of Delaware and its corporate headquarters are located at 600 Grant Street, Pittsburgh, PA 15219.

United States Steel Corporation produces iron and steel products for the automotive, construction, appliance, energy, containers, and packaging industries.

United States Steel Corporation is a publicly held company. United States Steel Corporation has no parent company and no publicly held company has a 10% or greater ownership interest in it.

Dated: August 22, 2023

Respectfully submitted,

/s/ John D. Lazzaretti
John D. Lazzaretti

CERTIFICATE OF COMPLIANCE WITH CIRCUIT RULES 18(A)(1) AND (A)(2)

The undersigned certifies that this motion for stay complies with Circuit Rule 18(a)(1). On August 4, 2023, Petitioner submitted to EPA a Petition for Reconsideration and Stay (Exhibit K) that requested an administrative stay pending judicial review of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023). EPA has not responded.

In accordance with Circuit Rule 18(a)(2), undersigned counsel notified EPA's counsel on August 11, 2023 that Petitioner planned to file this motion for stay. EPA notified Petitioner on August 21, 2023 that it opposes this motion and plans to file a response.

Dated: August 22, 2023

Respectfully submitted,

/s/ John D. Lazzaretti
John D. Lazzaretti

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GLOSSARY

EGU	Electric Generating Unit
FIP	Federal Implementation Plan
NAAQS	National Ambient Air Quality Standards
Proposed Rule	Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (April 6, 2022)
Rule	Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)
Screening Assessment	Screening Assessment of Potential Emission Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026, at 2 (Feb. 28, 2022)
SIP	State Implementation Plan
SIP Disapproval	Air Plan Disapprovals; Interstate Transport for Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9,336 (Feb. 13, 2023)

INTRODUCTION

Pursuant to Fed. R. App. P. 18(a)(2), Petitioner United States Steel Corporation ("U. S. Steel") seeks a stay pending judicial review of the United States Environmental Protection Agency's ("EPA's") final rule: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) ("Rule") as it applies to reheat furnaces (40 CFR 52.43) and boilers at iron and steel mills (40 CFR 52.45).

EPA lacks authority to promulgate the Rule for twelve States. Since the collective regulation of all upwind States was a foundational aspect of the Rule, the Rule can no longer stand on the current facts. The Rule's legal and procedural infirmities also strongly support its withdrawal or significant modification. In promulgating the Rule, EPA exceeded its statutory authority and violated the cooperative federalism principles on which the Clean Air Act, and the National Ambient Air Quality Standards ("NAAQS") in particular, are based.

The regulations for reheat furnaces bear no relationship to the proposed rule and have not been subject to notice and comment. They are also contrary to EPA's own findings on the record and overstep EPA's statutory authority. EPA's regulations for boilers at iron and steel mills similarly depart substantively from what was proposed and are not supported by the record for a substantial portion of the boilers EPA purports to regulate.

These infirmities individually and collectively demonstrate that U. S. Steel is likely to prevail on the merits. But unless the Rule is stayed, U. S. Steel must incur immediate and substantial costs while judicial review is pending. This waste of resources is unnecessary and serves no environmental benefit. A stay of the Rule pending judicial review is therefore justified and in the public interest.

BACKGROUND

Cooperative federalism is a "core principle" of the Clean Air Act. *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 511, n.14 (2014). For the NAAQS, it is embodied in a basic division of labor. While EPA is responsible for setting the NAAQS, states have "primary responsibility" for determining how to meet them. 42 U.S.C. §7407(a). Each state is to prepare a state implementation plan ("SIP") setting out the requirements that will apply within its borders. 42 U.S.C. §7410(a)(1). EPA has 12 months to review the SIP for completeness and an additional year to determine whether the SIP meets the requirements of the Clean Air Act. 42 U.S.C. §7410(k)(2) and (3). These "ministerial" reviews are not for EPA to substitute its judgment for the State's. *Texas v. EPA*, 829 F.3d 405, 411 (5th Cir. 2016) (quotations omitted). EPA looks only to whether the State's plan is "reasonably moored to the Act's provisions" and "based on a reasoned analysis." *Alaska Dept. of Envt'l. Conserv. v. EPA*, 540 U.S. 461, 485 and 490 (2004) (quotations omitted); *North Dakota v. EPA*, 730 F.3d 750 (8th Cir. 2013). If it is, EPA must approve it. *Id*. at §7410(k)(3). Only if a SIP is incomplete or does not meet the Act's requirements can EPA step in to promulgate its own federal implementation plan ("FIP") for the State. *Id*. at §7410(c)(1). EPA has two years to do this, during which the State can correct deficiencies. *Id*.

This is, at least, how the NAAQS are supposed to work. For the 2015 ozone NAAQS, most States submitted complete SIPs that met the requirements of the Clean Air Act. But while EPA was required to approve them within one year, EPA took no action for years. Instead, EPA developed new modeling that the States had no requirement or opportunity to address, and then disapproved the State's SIPs largely based on this new modeling. *See* 88 Fed. Reg. 9,336 (Feb. 13, 2023) (Exhibit B) ("SIP Disapproval").

While not required to address this new modeling, even if States had been willing to submit revised SIPs, EPA gave no opportunity to do so before promulgating its FIP. EPA proposed FIP less than two months after *proposing* to disapprove the SIPs. 87 Fed. Reg. 20,036 (April 6, 2022) (Exhibit C) ("Proposed Rule"). The following year, EPA finalized both rules in quick succession, promulgating the SIP Disapproval just one month before signing the FIP.[1] EPA's approach made it effectively impossible for most States to submit acceptable SIPs.

[1] *See* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

EPA's rush to finalize the Rule created significant additional problems. Procedurally, the finalized Rule departed significantly from the Proposed Rule in ways that were not logical outgrowths of the Proposed Rule. This included changing the modeling EPA used to support its regulatory action. As noted above, the Proposed Rule was improperly based on modeling that EPA developed after the States submitted their SIPs. When EPA finalized the Rule, it switched models yet again. *See* 88 Fed. Reg. at 36,673-74. The changes were significant. EPA incorporated "a raft of technical information and critiques" from comments on its prior modeling. *Id*. The status of some States changed entirely. *See* 88 Fed. Reg. at 9,367. More generally, the change in models redefined the emission reductions each state purportedly needed to address. *Compare* 87 Fed. Reg. at 20,071-72 *with* 88 Fed. Reg. at 36,709-11. This, in turn, changed the legal and technical issues commenters would need to address for each State. Yet while EPA's new modeling was central to the Rule, it was not subject to notice and comment. EPA released some of its results with the SIP Disapproval in February 2023, long after the close of public comment on the FIP. Even then, EPA inexplicably withheld a good portion of the modeling results, asserting they were "not applicable" to that rulemaking. 88 Fed. Reg. at 9,344, n.30. As a result, many of the results central to the Rule were not released until EPA posted them to its website in March 2023.[2]

[2] *See https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs*.

For iron and steel mills, the finalized Rule had more surprises. While EPA proposed emission limits for reheat furnaces,[3] the finalized Rule introduced a highly questionable "work plan" process instead, through which EPA asserts it will unilaterally "establish an emissions limit in the work plan that the affected unit must comply with." 88 Fed. Reg. at 36,879, 40 CFR 52.43(d)(3). Specifically, iron and steel mills are to install costly pollution controls nebulously designed to reduce emissions by "at least 40%" from a baseline rate (which is to be established in the future), and then use a "test-and-set" approach (which is also to be established in the future) to support a final emission limit, which EPA will set without going through notice-and-comment rulemaking. *Id.* at 36,818, -28. The Rule provides no criteria to cabin the arbitrary exercise of the Administrator's final decision-making authority, and the Rule sets out no process for challenging the Administrator's final decision.

For boilers at iron and steel mills, EPA proposed to regulate only those boilers that exceed an annual emissions threshold. 87 Fed. Reg. at 20,145. EPA proposed to use production capacity as an alternative applicability requirement. *Id.* In the finalized Rule, however, EPA uses "design capacity," despite acknowledging that this "captured more units than the EPA intended." 88 Fed. Reg. 36,819. While EPA also added exemptions for certain boilers, apparently to

[3] *See* 87 Fed. Reg. at 20,145, Table VII.C–3.

try to address this over-inclusion, *see id.*, these exemptions do not address many of the unsuspected, newly regulated boilers, and these exemptions were themselves not in the Proposed Rule or otherwise subject to notice and comment. Indeed, EPA asserted in the Proposed Rule that owners and operators "should begin engineering and financial planning now," creating the clear (but false) impression that the Rule would not radically change both the emission units subject to the rule and the engineering and financial commitments needed to comply. 87 Fed. Reg. at 20,036.

PROCEDURAL POSTURE

Numerous petitioners have challenged EPA's disapprovals of individual SIPs. To date, seven Circuits have stayed EPA's SIP Disapproval for twelve States.[4] An additional motion for stay is pending.[5] Since SIP disapproval is a prerequisite for EPA to promulgate its FIP, 42 U.S.C. §7410(c)(1), EPA has

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[4] Unpublished Order, *Texas v. EPA*, No. 23-60069, ECF 269-1 (5th Cir. May 1, 2023); Order, *Arkansas v. EPA*, No. 23-1320, ECF 5280996 (8th Cir. May 25, 2023); Order, *Missouri v. EPA*, No. 23-1719, ECF 5281126 (8th Cir. May 26, 2023); Unpublished Order, *Texas v. EPA*, No. 23-60069, ECF 359-2 (5th Cir. June 8, 2023); *Nevada Cement Co. v. EPA*, No. 23-682, ECF 27.1 (9th Cir. July 3, 2023); Order, *ALLETE, Inc. v. EPA*, No. 23-1776 (8th Cir. July 5, 2023); Order, *Kentucky v. EPA*, No. 23-3216, ECF 39-2 (6th Cir. July 25, 2023); Order, *Utah v. EPA*, No. 23-9509, ECF 010110895101 (10th Cir. July 27, 2023); Interim Stay Order, *West Virginia v. EPA*, No. 23-01418, ECF 39 (4th Cir. Aug. 10, 2023); Order, *Alabama v. EPA*, No. 23-11173 (11th Cir. Aug. 17, 2023).

[5] *See Ohio v. EPA*, Case No. 23-1183 (D.C. Cir).

recognized it must stay the Rule for States in which its SIP disapproval is stayed.[6] EPA's approach, however, has been to stay only the effective date of the Rule in these States, while leaving all other deadlines unchanged. *Id*. The result is a set of springing obligations that could apply at any time if the SIP stays are lifted.

For the remaining States subject to the Rule, EPA has taken no action, and appears set on applying the Rule as promulgated. This results in a Rule that is neither efficient nor equitable.

U. S. Steel petitioned for reconsideration and stay of the Rule on August 4, 2023. Exhibit K. EPA acknowledged receipt on August 14, 2023, but has not otherwise responded to U. S. Steel's petition.

STANDARD OF REVIEW

Courts consider four factors when determining whether to grant a stay:

(1) likelihood of success on the merits;

(2) the movant's irreparable injury;

(3) potential harm to other parties; and

(4) the public interest.

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[6] *See* 88 Fed. Reg. 49,295 (July 31, 2023) (Exhibit H); Notice of Forthcoming EPA Action to Address Additional Judicial Stay Orders, https://www.epa.gov/system/files/documents/2023-08/23-02403-OAR-OAP%20__Memo%20from%20J.%20Goffman%20re%20Response%20to%20Further%20Stay%20Orders%20_JG%20Signed%20%282%29.pdf (Aug. 2, 2023) (Exhibit I).

Nken v. Holder, 556 U.S. 418, 434 (2009). When the government is the opposing party, however, the third and fourth factors merge. *Id.* at 435.

ARGUMENT

I. U. S. Steel is Likely to Prevail on the Merits.

Because the Rule is legally, factually, and procedurally flawed, U. S. Steel is likely to prevail on the merits. EPA itself asserts that applying the Rule "across all jurisdictions" is "vital" to its "efficien[cy] and equit[y]." 88 Fed. Reg. at 36,691 (quotations omitted). While the Rule was never efficient or equitable, EPA cannot now apply the Rule in twelve States, undermining its own assertions of a viable Rule. The Rule was also not promulgated in accordance with law. It was based on a misinterpretation of EPA's statutory role and was rushed to the point that it violates the core tenets of cooperative federalism on which the Clean Air Act is based. For the iron and steel industry, the FIP lacks a factual basis for the requirements it imposes, and a substantial portion of the Rule was created after the close of public comment and with no notice or opportunity for public participation—just as EPA did with the States in disapproving the SIPs.

A. The Rule is No Longer Sustainable.

When EPA published the Rule, it addressed 23 States. 88 Fed. Reg. at 36,654. EPA repeatedly relied on this broad geographic reach, and the uniform application of requirements to each State, to support the level of emission reductions required by the Rule, to avoid generation and production shifting to less regulated States, to assure electric generation reliability, and to generally avoid inequity and undue hardship on industry, the States, and the nation. *See, e.g.*, 88 Fed. Reg. at 36,673, 36,691, 36,713, 36,716, 36,746. U. S. Steel and others challenged the accuracy of EPA's assertions. *See* United States Steel Corporation Comments on Proposed Federal Implementation Plan, EPA-HQ-OAR-2021-0668-0798 (June 21, 2022) (Exhibit D). But by EPA's own admission "consistency in rule requirements across all jurisdictions" was "vital" to ensuring the rule was "efficient and equitable." 88 Fed. Reg. at 36,691 (quotations omitted). Under even EPA's interpretation, therefore, there is nothing "efficient and equitable" in the Rule as it currently stands.

As of the filing of this Motion, the Rule does not now apply in over half the States that EPA used to justify the Rule. *See* footnote 2, *supra.* Moreover, because stays are predicated on likelihood of success on the merits, *see Nken*, 556 U.S. at 434, it is likely the Rule will never apply in some or all of these States. This alone renders the Rule arbitrary and capricious. *Motor Vehicle Mfrs. Ass'n. of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *Sierra Club v. EPA*, 884 F. 3d 1185, 1198 (D.C. Cir. 2018) (arbitrary and capricious to rely on assumptions that are counter to the evidence).

B. The Rule Violates the Clean Air Act and Cooperative Federalism.

EPA must follow both the letter of the Clean Air Act and interpret its obligations "with a view to their place in the overall statutory scheme." *Util. Air Regul. Grp. v. EPA*, 573 U.S. 302, 322 (2014) (quotation omitted). EPA violated both the letter and spirit of the Act when it delayed its statutory duty to approve SIPs, not because of inconsistency with the Act, but because EPA preferred different modeling, and then rushed out a FIP before the States could address EPA's SIP disapprovals.

The Clean Air Act is "an experiment in cooperative federalism." *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001). EPA sets the NAAQS, but the States are given "primary responsibility" for ensuring emissions within the State comply with them. 42 U.S.C. §7407(a). EPA has 12 months to review complete SIPs to determine if they meet the applicable statutory requirements. 42 U.S.C. §7410(k)(2). If they do, EPA must approve them. *Id.* at §7410(k)(3).

The majority of States subject to the Rule submitted SIPs that met the applicable statutory requirements. EPA was therefore required to approve them. *Id.* Instead, EPA delayed for years until it had produced new modeling it contended undermined the States' analyses. But failure to timely act on a SIP does not empower EPA to disregard its statutory obligations, let alone permit EPA to move the goalposts on the States after the fact, or require them to address new modeling that was not mandated by the Clean Air Act. *See Wyoming v. EPA*, No. 14-9529, 2023 WL 5214083, at *6 (10th Cir. Aug. 15, 2023) (approving a SIP only if it followed nonbinding guidelines would "effectively re-write the Act"). In doing so, EPA improperly extended its FIP authority to States that had properly retained their primary regulatory authority.

EPA then compounded its error by rushing to simultaneously promulgate its FIP. The Clean Air Act sets no minimum time EPA must wait after disapproving a SIP before it can issue a FIP,[7] but Congress clearly intended cooperative federalism to apply during this time; it expressly gave States the ability to correct deficiencies, and prevent EPA from promulgating a FIP, if correction is approved before EPA promulgates its FIP. 42 U.S.C. §7410(c)(1). By simultaneously promulgating its own FIP with the SIP disapprovals, EPA cut off all meaningful opportunity for States to serve the role intended by Congress and failed to honor EPA's secondary role in the statutory scheme. *Util. Air Regul. Grp.*, 573 U.S. at 322; 42 U.S.C. §7407(a); *Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 79 (1975) (the Clean Air Act "plainly" relegates EPA to "a secondary role").

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[7] *EME Homer*, 572 U.S. at 509.

C. EPA Did Not Support the Regulation of Iron and Steel Mills.

EPA is obligated to avoid over-control (imposing more obligations on upwind States than necessary to meet the requirements of the Clean Air Act). *EME Homer*, 572 U.S. at 523. Thus, the Rule does not regulate every source in each applicable State. Instead, EPA attempted to focus on "the most impactful industries and emissions units." 88 Fed. Reg. at 36,682. EPA started with electric generating units ("EGUs"), then screened 41 so-called "non-EGU" industries to identify "the most emissions reductions" that could be achieved at a marginal cost threshold. Screening Assessment of Potential Emission Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026, at 2 (Feb. 28, 2022) (Exhibit E) ("Screening Assessment"). "[W]ell-controlled sources" were expressly "excluded from consideration." *Id*. at 3.

For the Screening Assessment, EPA assumed, incorrectly, that emissions from numerous sources at iron and steel mills, including co-fired boilers, blast furnaces, and basic oxygen furnaces, had "potentially controllable emissions" that, when combined, led EPA to conclude it should be one of nine non-EGU industries subject to the FIP. *See id*. at 17, Table 6. In the Rule, EPA appropriately recognizes that additional emission reductions from most of these sources are not technologically or economically feasible. *See* 88 Fed. Reg. at 36,827 ("the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of…control technologies…is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry"); *id*. at 36,833 ("The EPA does not have sufficient information at this time to conclude that [boilers] burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost."). The Rule therefore regulates only reheat furnaces and certain boilers. 88 Fed. Reg. at 36,664. As a result, the Screening Assessment significantly overcounted emissions from iron and steel mills.

This required updating before EPA relied on the Screening Assessment in the Rule. EPA did not release sufficient data with the Screening Assessment for the public to reconstruct EPA's assessment with just sources subject to the finalized Rule,[8] but re-assessment would likely support excluding iron and steel from the Rule; it was already the lowest-emitting industry included in the FIP before excluding most source categories. *See* Screening Assessment at Table A-3. Yet while EPA conducted a supplemental screening assessment for another industry, EPA did not do so for iron and steel. 88 Fed. Reg. at 36,734. Instead, EPA continued to rely on its original, obsolete, and incorrect, Screening Assessment. 88 Fed. Reg. at 36,732-33. This resulted in the inconsistent treatment

[8] This alone raises notice and comment problems, as raised by U. S. Steel in its comments. Exhibit D at 11, 15-16.

of iron and steel mills as compared with other industries with comparable "potentially controllable emissions," and, ultimately, in a rule that is inconsistent with the record. *State Farm*, 463 U.S. at 43 (arbitrary and capricious to offer an explanation that "runs counter to the evidence before the agency").

D. The Rule Was Not Subject to Adequate Notice and Comment.

If "documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of [Clean Air Act] section 307 would have been violated." *Sierra Club v. Costle*, 657 F.2d 298, 398 (D.C. Cir. 1981). Several aspects of the Rule rely on information that EPA did not include in the public record in time for meaningful public comment.

The most generally applicable example is the modeling EPA used to support the Rule. This modeling was central both to EPA determination of which States would be subject to the Rule and the level of emission reductions the States need to achieve. *See* 88 Fed. Reg. at 36,673-74. But this modeling was not published until months after the close of public comment, with a significant portion made available only with the final Rule. *Id.* This was "highly improper." *Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 508, 540 (D.C. Cir. 1983); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (the "safety valves in the use of such sophisticated methodology [as computer modeling] are the requirement of public exposure of the assumptions and data incorporated into the analysis and the acceptance and consideration of public comment.") (quotations omitted).

EPA has argued the public had access to other models. 88 Fed. Reg. at 36,674. But the modeling EPA used for its final Rule differs significantly from prior modeling. Petitioners, including U. S. Steel, have already raised technical flaws specific to EPA's latest modeling, including: (1) errors in the data EPA used for the model; (2) substantial bias at locations material to EPA's conclusions; and (3) systematic overprediction of emissions from several States that, if corrected, could change the applicability of the FIP. *See* Petition for Reconsideration and Stay, EPA-HQ-OAR-2021-0663-0091 (April 14, 2023) (Exhibit F); Petition for Reconsideration and Stay of the Good Neighbor Plan (Aug. 4, 2023) (Exhibit G). EPA has itself recently solicited public comment on its new modeling, but only as applied to one State, Wyoming. 88 Fed. Reg. 54,998 (Aug. 14, 2023) (Exhibit J). EPA offers no reasons why an additional comment period is necessary for Wyoming but not States subject to the Rule. *Id.*

Key aspects of the Rule applicable to iron and steel mills were also neither referenced in, nor logical outgrowths from, the Proposed Rule. Under both the Clean Air Act and Administrative Procedure Act, "the final rule must be a 'logical outgrowth' of the agency's proposal." *Small Ref.*, 705 F2d at 543 (*quoting United*

Steelworkers v. Marshall, 647 F.2d 1189, 1221 (D.C. Cir. 1980), *cert. denied*, 453 U.S. 913 (1981)). The entire regulation of reheat furnaces (40 CFR 52.43) is based on a "test-and-set" approach that can be found nowhere in the Proposed Rule. 88 Fed. Reg. at 36,818. For boilers, EPA proposed to regulate units based on annual emissions or production. 87 Fed. Reg. at 20,181. Yet without notice, EPA switched to regulating boilers by "design capacity." 88 Fed. Reg. at 36,884. This was a significant departure, which EPA acknowledges captured more boilers than originally proposed. *Id*. at 36,819.

EPA did not afford notice and opportunity for comment on the most fundamental elements of its reheat furnace and boiler regulations for iron and steel mills. This was arbitrary and capricious and violated the procedural requirements of the Clean Air Act. *Small Ref.*, 705 F.2d at 543; 42 U.S.C. §7607(d).

E. EPA's "Test-And-Set" Approach Reheat Furnaces Is Illegal and Lacks Record Support.

EPA's test-and-set approach for reheat furnaces was adopted in response to comments that the emission limits in the Proposed Rule were unsupported by the record. 88 Fed. Reg. at 36,818. In response, EPA correctly concluded that the proposed limits were unsupported. But while this justified removal of reheat furnaces from the Rule, EPA instead implemented a process that attempts to circumvent the lack of sufficient data by requiring owners and operators to install controls, then send EPA data to support a future emission limit. *Id*. This offers flexibility at the cost of statutory protections that EPA has no authority to remove. It also confers on EPA a power to decide who can and cannot operate that the Clean Air Act never intended.

Specifically, the Rule requires owners and operators to "install and operate" pollution control technology "designed to achieve at least a 40% reduction from baseline" emissions. 88 Fed. Reg. at 36,879, 40 CFR 52.43(c). No further guidance is offered on what designs will be accepted by EPA. The Rule also does not say how an emission limit is then to be set, other than that the owner or operator is to submit a work plan and "establish an emissions limit in the work plan that the affected unit must comply with." *Id.*, 40 CFR 52.43(d)(3).

The 40% design requirement is itself arbitrary, since EPA claims it is based on installation of a technology, "low-NOx burners," that EPA asserted in the Proposed Rule achieved only a 20% reduction. *See* 87 Fed. Reg. at 20,145, Table VII.C-3. But beyond this, the entire work plan process is legally unsound. If EPA lacks the relevant data to support an action, it cannot act. *State Farm*, 463 U.S. at 43 (an agency must offer a "rational connection between the facts found and the choice made") (quotations omitted). EPA cannot promulgate a placeholder, and then add information to support its decision after the fact. *Id.*; 42 U.S.C. §7607(d)(6)(C) ("The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation.").

The Clean Air Act also sets forth procedural requirements EPA must follow to impose emission limits in a FIP. 42 U.S.C. §7607(d). This includes publication of the proposed rule in the Federal Register, provision of a statement of basis and purposes, creation of a public docket of supporting material, public comment, and response to significant comments. *Id.* at §7410(d)(3)-(6). Public participation must be for "a reasonable period" and "at least 30 days" unless expressly provided for otherwise in the Clean Air Act. *Id.* at §7607(h). Final emission limitations are also subject to judicial review. *Id.* at §7410(d)(7). For example, when EPA adopted a test-and-set process in another FIP, it promulgated a range of emission limits, a procedure to establishing final limits within that range, including the data and equations that would be used, and provided that a final emission limit would become enforceable "only after EPA's confirmation or modification of the emission limit" in a final agency action published in the Federal Register. *See, e.g.*, 40 CFR 42.1235(b)(1)(ii)(A)(1)-(7).

The Rule provides no such process. There is no publication of proposed or final emission limits in the Federal Register; the Administrator will simply notify owners and operators electronically whether their plan is approved. 88 Fed. Reg. at 36,880, 40 CFR 52.43(d)(4)(iv). If the Administrator does not approve, the owner or operator has only 15 calendar days to present additional information or arguments, after which the Administrator can issue a final decision disapproving the work plan. *Id.*, 40 CFR 52.43(d)(4)(iii). If the Administrator disapproves a work plan or finds a work plan was not timely submitted or completed, "[e]ach day that the affected unit operates following such disapproval or failure to submit shall constitute a violation." *Id.*, 40 CFR 52.43(d)(v).

In other words, EPA can prohibit operation on 15 days' notice without a hearing or notice-and-comment rulemaking. This finds no support in the Clean Air Act. Indeed, where Congress has granted EPA authority to limit emissions from specific sources to address interstate transport violations, Congress required both a public hearing and at least three months for the source to come into compliance. 42 U.S.C. §7426(b). EPA's regulations for reheat furnaces fall short of this process and any other process that might satisfy the requirements of the Clean Air Act.

II. Absent a Stay, U. S. Steel Will Suffer Imminent Irreparable Harm.

The Rule poses substantial and imminent injuries to U. S. Steel. EPA itself warned owners and operators that they should "begin engineering and financial planning" as of the date of the Proposed Rule to be able to meet EPA's implementation timetable. 87 Fed. Reg. at 20,036. Notwithstanding the fact that it is unreasonable to suggest that significant funds and resources be used to implement a proposed rule that is subject to change (as the Rule has changed), the Rule followed through on EPA's threat, and imposes an unreasonably short schedule. As discussed in the attached Declaration of Alexis Piscitelli, at ¶¶6-10 (Exhibit L), the Rule allows insufficient time for design, permitting, and installation of controls; likely years less than what will be required. As a result, absent a stay, U. S. Steel cannot wait before it must incur substantial costs on work plans that EPA does not have the authority to impose, and on the design, permitting and installation of boiler and reheat furnace modifications that are unnecessary and may be subject to withdrawal or modification in a revised rule. These substantial costs are imposed without adherence to law and constitute an irreparable harm. *See Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) ("complying with a regulation later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs") (Scalia, J., concurring in part and in the judgment).

U. S. Steel has already needed to incur significant costs to begin addressing the Rule's requirements. Exhibit L at ¶¶3, 11-20. The capital expenditures alone (excluding testing, monitoring, recordkeeping, and reporting costs) for just one U. S. Steel facility will cost between $28 and $46 million. *Id.* at ¶15. These costs are not recoverable "in the ordinary course of litigation," and are an irreparable harm as well. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015) (quotations omitted).

III. A Stay Will Not Significantly Injure Other Parties and Is in the Public Interest.

While costs would need to be incurred to meet EPA's unreasonable schedule, emissions reductions from iron and steel sources do not occur until 2026. 88 Fed. Reg. at 36,654. As a result, a stay will not affect emissions during judicial review. As discussed above, EPA's defective Screening Analysis also significantly overstated potential emission reductions from the iron and steel industry. A more accurate assessment likely excludes iron and steel entirely, resulting in no harm from a stay. The Rule is also stayed already in 12 States, so a stay will not affect emissions from reheat furnaces and boilers in those States during that litigation.

On the other hand, a reliable and sufficient supply of domestic steel is in the public interest. The cumulative effect of the immediate burdens of the Rule, with several other regulations EPA has imposed or proposed for the domestic steel industry, is having a compounding effect that places unnecessary strain on domestic steel production. *See* Exhibit L at ¶¶21-29. This has both national economic and national security implications. *See id*. To comply with the Rule, U. S. Steel will need to take multiple outages to retrofit reheat furnaces and boilers. These outages will impact production capabilities and may lead to the flaring of by-product fuels. *See id.* at ¶¶18-19. Furthermore, the availability of qualified vendors and experts to implement the Rule is limited, which exacerbates the scheduling problems, further rendering the Rule unworkable. *Id.* at ¶¶6-10.

The public also has a fundamental interest "in having governmental agencies abide by the federal laws that govern their existence and operations." *League of Women Voters of U.S. v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016). As discussed above, the Rule is without statutory authority and was promulgated through the inequitable exclusion of public participation on information central to EPA's action. The result will be costly and needless public expenditures, both by U. S. Steel and the States that must act on the hundreds of permit applications the Rule requires. Here, a stay is necessary to prevent this waste and avoid implementation of an unlawful rule pending judicial review. *Id.* at 12 ("there is generally no public interest in the perpetuation of unlawful agency action").

CONCLUSION

For the foregoing reasons, Petitioner United States Steel Corporation respectfully requests that this Court stay the Rule for reheat furnaces (40 CFR 52.43) and boilers at iron and steel mills (40 CFR 52.45).

August 22, 2023

Respectfully Submitted,

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Certificate of Compliance

Pursuant to Fed. R. App. P. 32(a)(5)-(7) and D.C. Circuit Rules 27(a)(2) and 32, I certify that:

This motion complies with the type-volume limitations of Fed. R. App. P. 27(d)(2)(A) because it contains 5,184 words, excluding the parts of the motion exempted by Fed. R. App. P. 32(f) and 27(a)(2)(B).

This motion complies with the typeface and type style requirements of Fed. R. App. P. 27(d)(1)(E) because this brief has been prepared in a proportionately spaced typeface using Microsoft Word Times New Roman 14-point font.

Dated: August 22, 2023

/s/ John D. Lazzaretti
John D. Lazzaretti

Certificate of Service

I hereby certify that on this 22 day of August, 2023, I filed the foregoing Motion for Stay with the Clerk of the Court using the CM/ECF System, which will send notice of such filing to all registered CM/ECF users.

Dated: August 22, 2023

/s/ John D. Lazzaretti
John D. Lazzaretti

Motion to Stay, *United States Steel Corporation v. EPA, et al.*, Case No. 23-1207 (D.C. Cir.)

<u>Index of Exhibits</u>

Exhibit A	Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)
Exhibit B	Air Plan Disapprovals; Interstate Transport for Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9,336 (Feb. 13, 2023)
Exhibit C	Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (Apr. 6, 2022)
Exhibit D	United States Steel Corporation Comments on Proposed Federal Implementation Plan, EPA-HQ-OAR-2021-0668-0798 (June 21, 2022)
Exhibit E	Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 (Feb. 28, 2022)
Exhibit F	Petition for Reconsideration and Stay, EPA-HQ-OAR-2021-0663-0091 (April 14, 2023).
Exhibit G	Petition for Reconsideration and Stay of the Final Rule: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards (Aug. 4, 2023)
Exhibit H	Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 Fed. Reg. 49,295 (July 31, 2023)
Exhibit I	Notice of Forthcoming EPA Action to Address Additional Stay Orders (Aug. 2, 2023)

Exhibit J	Air Plan Approval; Wyoming; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 54,998 (Aug. 14, 2023)
Exhibit K	Petition For Reconsideration and for Stay of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards (Aug. 4, 2023)
Exhibit L	Declaration of Alexis Piscitelli in Support of United States Steel Corporation's Motion for Stay (Aug. 22, 2023)

Motion to Stay, *United States Steel Corporation v. EPA, et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit A

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78, and 97

[EPA–HQ–OAR–2021–0668; FRL–8670–02–OAR]

RIN 2060–AV51

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes Federal Implementation Plan (FIP) requirements to address 23 states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standards (NAAQS) in other states. The U.S. Environmental Protection Agency (EPA) is taking this action under the ''good neighbor'' or ''interstate transport'' provision of the Clean Air Act (CAA or Act). The Agency is defining the amount of ozone-precursor emissions (specifically, nitrogen oxides) that constitute significant contribution to nonattainment and interference with maintenance from these 23 states. With respect to fossil fuel-fired power plants in 22 states, this action will prohibit those emissions by implementing an allowance-based trading program beginning in the 2023 ozone season. With respect to certain other industrial stationary sources in 20 states, this action will prohibit those emissions through emissions limitations and associated requirements beginning in the 2026 ozone season. These industrial source types are: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

DATES: This final rule is effective on August 4, 2023.

ADDRESSES: The EPA has established a docket for this rulemaking under Docket ID No. EPA–HQ–OAR–2021–0668. All documents in the docket are listed in the *https://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically at *https://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA Docket Center, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Office of Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Elizabeth Selbst, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–01), Environmental Protection Agency, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (312) 886–4746; email address: *selbst.elizabeth@epa.gov*.

SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

2016v1 2016 Version 1 Emissions Modeling Platform
2016v2 2016 Version 2 Emissions Modeling Platform
4-Step Framework 4-Step Interstate Transport Framework
ABC Associated Builders and Contractors
ACS American Community Survey
ACT Alternative Control Techniques
AEO Annual Energy Outlook
AQAT Air Quality Assessment Tool
AQS Air Quality System
BACT Best Available Control Technology
BART Best Available Retrofit Technology
BOF Basic Oxygen Furnace
BPT Benefit Per Ton
C1C2 Category 1 and Category 2
C3 Category 3
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCR Coal Combustion Residual
CDC Centers for Disease Control and Prevention
CDX Central Data Exchange
CEDRI Compliance and Emissions Data Reporting Interface
CEMS Continuous Emissions Monitoring Systems
CES Clean Energy Standards
CFB Circulating Fluidized Bed Units
CHP Combined Heat and Power
CMDB Control Measures Database
CMV Commercial Marine Vehicle
CoST Control Strategy Tool
CPT Cost Per Ton
CRA Congressional Review Act
CSAPR Cross-State Air Pollution Rule
DAHS Data Acquisition and Handling System
DOE Department of Energy
EAF Electric Arc Furnace
EGU Electric Generating Unit
EIA U.S. Energy Information Agency
EIS Emissions Inventory System
EISA Energy Independence and Security Act
ELG Effluent Limitation Guidelines
E.O. Executive Order
EPA or the Agency United States Environmental Protection Agency
ERT Electronic Reporting Tool
FERC Federal Energy Regulatory Commission
FFS Findings of Failure to Submit
FIP Federal Implementation Plan
GIS Geographic Information System
g/hp-hr grams per horsepower per hour
HDGHG Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
HEDD High Electricity Demand Days
ICI Industrial, Commercial, and Institutional
I/M Inspection and Maintenance
IPM Integrated Planning Model
IRA Inflation Reduction Act
LAER Lowest Achievable Emission Rate
LDC Local Distribution Company
LME Low Mass Emissions
LNB Low-NO_X Burners
MATS Mercury and Air Toxics Standards
MCM Menu of Control Measures
MDA8 Maximum Daily Average 8-Hour
MJO Multi-Jurisdictional Organization
MOU Memorandum of Understanding
MOVES Motor Vehicle Emissions Simulator
MSAT2 Mobile Source Air Toxics Rule
MWC Municipal Waste Combustor
NAAQS National Ambient Air Quality Standards
NACAA National Association of Clean Air Agencies
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NEI National Emissions Inventory
NERC North American Electric Reliability Corporation
NESHAP National Emissions Standards for Hazardous Air Pollutants
NMB Normalized Mean Bias
NME Normalized Mean Error
No SISNOSE No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU Non-Electric Generating Unit
NODA Notice of Data Availability
NO_X Nitrogen Oxides
NREL National Renewable Energy Lab
NSCR Non-Selective Catalytic Reduction
NSPS New Source Performance Standard
NSR New Source Review
NTTAA National Technology Transfer and Advancement Act
OFA Over-Fire Air
OMB United States Office of Management and Budget

OSAT/APCA Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis
OTC Ozone Transport Commission
OTR Ozone Transport Region
OTSA Oklahoma Tribal Statistical Area
PDF Portable Document Format
PEMS Predictive Emissions Monitoring Systems
$PM_{2.5}$ Fine Particulate Matter
ppb parts per billion
ppm parts per million
ppmv parts per million by volume
ppmvd parts per million by volume, dry
PRA Paperwork Reduction Act
PSD Prevention of Significant Deterioration
PTE Potential to Emit
RACT Reasonably Available Control Technology
RATA Relative Accuracy Test Audit
RCF Relative Contribution Factor
RFA Regulatory Flexibility Act
RICE Reciprocating Internal Combustion Engines
ROP Rate of Progress
RPS Renewable Portfolio Standards
RRF Relative Response Factor
RTC Response to Comments
RTO Regional Transmission Organization
SAFETEA Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCC Source Classification Code
SCR Selective Catalytic Reduction
SIL Significant Impact Level
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
tpd ton per day
TAS Treatment as State
TSD Technical Support Document
UMRA Unfunded Mandates Reform Act
VMT Vehicle Miles Traveled
VOCs Volatile Organic Compounds
WRAP Western Regional Air Partnership
WRF Weather Research and Forecasting

Table of Contents

I. Executive Summary

This final rule resolves the interstate transport obligations of 23 states under CAA section 110(a)(2)(D)(i)(I), referred to as the ‘‘good neighbor provision’’ or the ‘‘interstate transport provision’’ of the Act, for the 2015 ozone NAAQS. On October 1, 2015, the EPA revised the primary and secondary 8-hour standards for ozone to 70 parts per billion (ppb).[1] States were required to submit to EPA ozone infrastructure State Implementation Plan (SIP) revisions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018. The EPA proposed the subject rule to address outstanding interstate ozone transport obligations for the 2015 ozone NAAQS in the **Federal Register** on April 6, 2022 (87 FR 20036).

The EPA is making a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in downwind states, based on projected ozone precursor emissions in the 2023 ozone season. The EPA is issuing FIP requirements to eliminate interstate transport of ozone precursor emissions from these 23 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in downwind states. The EPA is not finalizing its proposed error correction for Delaware's ozone transport SIP, and we are deferring final action at this time on the proposed FIPs for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action. As discussed in section III of this document, the EPA's updated analysis of 2023 suggests that the states of Arizona, Iowa, Kansas, and New Mexico may be significantly contributing to one or more nonattainment or maintenance receptors. The EPA is not making any final determinations with respect to these states in this action but intends to address these states, along with Tennessee and Wyoming, in a subsequent action or actions.

The EPA is finalizing FIP requirements for 21 states for which the Agency has, in a separate action, disapproved (or partially disapproved) ozone transport SIP revisions that were submitted for the 2015 ozone NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Texas, Utah, West Virginia, and Wisconsin. *See* 88 FR 9336. In this final rule, the EPA is issuing FIPs for two states—Pennsylvania and Virginia—for which the EPA issued Findings of Failure to Submit for 2015 ozone NAAQS transport SIPs. *See* 84 FR 66612 (December 5, 2019). Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction.[2]

This final rule defines ozone season nitrogen oxides (NO_X) emissions

[1] *See* 80 FR 65291 (October 26, 2015).

[2] In general, specific tribal names or reservations are not identified separately in this final rule except as needed. *See* section III.C.2 of this document for further discussion about the application of this rule in Indian Country.

performance obligations for Electric Generating Unit (EGU) sources and fulfills those obligations by implementing an allowance-based ozone season trading program beginning in 2023. This rule also establishes emissions limitations beginning in 2026 for certain other industrial stationary sources (referred to generally as ''non-Electric Generating Units'' (non-EGUs)). Taken together, these regulatory requirements will fully eliminate the amount of emissions that constitute the covered states' significant contribution to nonattainment and interference with maintenance in downwind states for purposes of the 2015 ozone NAAQS.

This final rule implements the necessary emissions reductions as follows. Under the FIP requirements, EGUs in 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) are required to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[3] In addition to reflecting emissions reductions based on the Agency's determination of the necessary control stringency in this rule, the revised trading program includes several enhancements to the program's design to better ensure achievement of the selected control stringency on all days of the ozone season and over time. For 12 states already required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) under the Revised CSAPR Update (with respect to the 2008 ozone NAAQS), the FIPs are amended by the revisions to the Group 3 trading program regulations. For seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is issuing new FIPs for two states (Alabama and Missouri) and amending existing FIPs for five states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. The EPA is issuing new FIPs for three states not currently covered by any CSAPR NO_X ozone season trading program: Minnesota, Nevada, and Utah.

This rulemaking requires emissions reductions in the selected control stringency to be achieved as expeditiously as practicable and, to the extent possible, by the next applicable nonattainment dates for downwind areas for the 2015 ozone NAAQS. Thus, initial emissions reductions from EGUs will be required beginning in the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS.

The remaining emissions reduction obligations will be phased in as soon as possible thereafter. Substantial additional reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs, also referred to in this action as industrial sources, will phase in beginning in the 2026 ozone season, associated with the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. The EPA had proposed to require all emissions reductions to eliminate significant contribution to be in place by the 2026 ozone season. While we continue to view 2026 as the appropriate analytic year for purposes of applying the 4-step interstate transport framework, as discussed in section V.D.4 and VI.A.2 of this document, the final rule will allow individual facilities limited additional time to fully implement the required emissions reductions where the owner or operator demonstrates to the EPA's satisfaction that more rapid compliance is not possible. For EGUs, the emissions trading program budget stringency associated with retrofit of post-combustion controls will be phased in over two ozone seasons (2026–2027). For industrial sources, this final rule provides a process for individual facilities to seek a one year extension, with the possibility of up to two additional years, based on a specific showing of necessity.

The EGU emissions reductions are based on the feasibility of control installation for EGUs in 19 states that remain linked to downwind nonattainment and maintenance receptors in 2026. These 19 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The emissions reductions required for EGUs in these states are based primarily on the potential retrofit of additional post-combustion controls for NO_X on most coal-fired EGUs and a portion of oil/gas-fired EGUs that are currently lacking such controls.

The EPA is finalizing, with some modifications from proposal in response to comments, certain additional features in the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets and recalibration of the allowance bank over time as well as backstop daily emissions rate limits for large coal-fired units. The purpose of these enhancements is to better ensure that the emissions control stringency the EPA found necessary to eliminate significant contribution at Step 3 of the 4-step interstate transport framework is maintained over time in Step 4 implementation and is durable to changes in the power sector. These enhancements ensure the elimination of significant contribution is maintained both in terms of geographical distribution (by limiting the degree to which individual sources can avoid making emissions reductions) and in terms of temporal distribution (by better ensuring emissions reductions are maintained throughout each ozone season, year over year). As we further discuss in section V.D of this document, these changes do not alter the stringency of the emissions trading program over time. Rather, they ensure that the trading program (as the method of implementation at Step 4) remains aligned with the determinations made at Step 3. These enhancements are further discussed in section VI.B of this document.

The EPA is making a finding that NO_X emissions from certain non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS and that cost-effective controls for NO_X emissions reductions are available in certain industrial source categories that would result in meaningful air quality improvements in downwind receptors. The EPA is establishing emissions limitations beginning in 2026 for non-EGU sources located within 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. The final rule establishes NO_X emissions limitations during the ozone season for the following unit types for sources in

[3] As explained in section V.C.1 of this document, the EPA is making a finding that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

non-EGU industries:[4] reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

A. Purpose of the Regulatory Action

The purpose of this rulemaking is to protect public health and the environment by reducing interstate transport of certain air pollutants that significantly contribute to nonattainment, or interfere with maintenance, of the 2015 ozone NAAQS in downwind states. Ground-level ozone has detrimental effects on human health as well as vegetation and ecosystems. Acute and chronic exposure to ozone in humans is associated with premature mortality and certain morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems by limiting tree growth, causing foliar injury, and changing ecosystem community composition. Section III of this document provides additional evidence of the harmful effects of ozone exposure on human health and the environment. Studies have established that ozone air pollution can be transported over hundreds of miles, with elevated ground-level ozone concentrations occurring in rural and metropolitan areas.[5 6] Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO_X emissions are an effective method to reduce regional-scale ozone transport.[7]

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS.[8] Within 3 years of the EPA promulgating a new or revised NAAQS, all states are required to provide SIP submittals, often referred to as ''infrastructure SIPs,'' addressing certain requirements, including the good neighbor provision. *See* CAA section 110(a)(1) and (2). The EPA must either approve or disapprove such submittals or make a finding that a state has failed to submit a complete SIP revision. As with any other type of SIP under the Act, when the EPA disapproves an interstate transport SIP or finds that a state failed to submit an interstate transport SIP, the CAA requires the EPA to issue a FIP to directly implement the measures necessary to eliminate significant contribution under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this rule, the EPA is finalizing requirements to fully address good neighbor obligations for the covered states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c). By eliminating significant contribution from these upwind states, this rule will make substantial and meaningful improvements in air quality by reducing ozone levels at the identified downwind receptors as well as many other areas of the country. At any time after the effective date of this rule, states may submit a Good Neighbor SIP to replace the FIP requirements contained in this rule, subject to EPA approval under CAA section 110(a).

The EPA conducted air quality modeling for the 2023 and 2026 analytic years to identify (1) the downwind areas identified as ''receptors'' (which are associated with monitoring sites) that are expected to have trouble attaining or maintaining the 2015 ozone NAAQS in the future and (2) the contribution of ozone transport from upwind states to the downwind air quality problems. We use the term ''downwind'' to describe those states or areas where a receptor is located, and we use the term ''upwind'' to describe states whose emissions are linked to one or more receptors. States may be both downwind and upwind depending on the receptor or linkage in question. Section IV of this document provides a full description of the results of the EPA's updated air quality modeling and relevant analyses for the rulemaking, including a discussion of how updates to the modeling and air quality analysis following the proposed rule have resulted in some modest changes in the overall geography of the final rule. Based on the EPA's air quality analysis, the 23 upwind states covered in this action are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in downwind states. The EPA intends to expeditiously review the updated air quality modeling and related analyses to address potential good neighbor requirements of six additional states—Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming—in a subsequent action. The EPA had previously approved 2015 ozone transport SIPs submitted by Oregon and Delaware, but in the proposed FIP action the EPA found these states potentially to be linked in the modeling supporting our proposal. We proposed to issue an error correction for our prior approval of Delaware's 2015 ozone transport SIP; however, in this final rule, the EPA is withdrawing the proposed error correction and the proposed FIP for Delaware, because our updated modeling for this final rule confirms that Delaware is not linked above the 1 percent of NAAQS threshold (*see* section III.C.1 of this document for additional information). The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

1. Emissions Limitations for EGUs Established by the Final Rule

In this rule, the EPA is issuing FIP requirements that apply the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program as revised in the rule to EGU sources within the borders of the following 22 states: Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. Implementation of the revised trading program provisions begins in the 2023 ozone season.

The EPA is expanding the CSAPR NO_X Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs require power plants within the borders of the 22 states listed in the previous paragraph to participate in an expanded and revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of the following 12 states currently participating in the Group 3 Trading Program under existing FIPs remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland,

[4] We use the terms ''emissions limitation'' and ''emissions limit'' to refer to both numeric emissions limitations and control technology requirements that specify levels of emissions reductions to be achieved.

[5] Bergin, M.S. et al. (2007) Regional air quality: local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[6] Liao, K. et al. (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100–112.

[7] *See* 82 FR 51238, 51248 (November 3, 2017) [citing 76 FR 48208, 48222 (August 8, 2011)] and 63 FR 57381 (October 27, 1998).

[8] 42 U.S.C. 7410(a)(2)(D)(i)(I).

Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs also require affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'') under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.[9] Finally, the EPA is issuing new FIPs for EGUs within the borders of three states not currently covered by any existing CSAPR trading program for seasonal NO_X emissions: Minnesota, Nevada, and Utah. Sources in these states will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[10] Refer to section VI.B of this document for details on EGU regulatory requirements.

2. Emissions Limitations for Industrial Stationary Point Sources Established by the Final Rule

The EPA is issuing FIP requirements that include new NO_X emissions limitations for industrial or non-EGU sources in 20 states, with sources expected to demonstrate compliance no later than 2026. The EPA is requiring emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the following 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia and West Virginia.

The EPA is establishing emissions limitations for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. Refer to Table II.A–1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this rule.

B. Summary of the Regulatory Framework of the Rule

The EPA is applying the 4-step interstate transport framework developed and used in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules under the authority provided in CAA section 110(a)(2)(D)(i)(I). The 4-step interstate transport framework provides a stepwise method for the EPA to define and implement good neighbor obligations for the 2015 ozone NAAQS. The four steps are as follows: (Step 1) identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (Step 2) determining which upwind states contribute to these identified problems in amounts sufficient to ''link'' them to the downwind air quality problems (*i.e.,* in this rule as in prior transport rules beginning with CSAPR in 2011, above a contribution threshold of 1 percent of the NAAQS); (Step 3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS through a multifactor analysis; and (Step 4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implementing the necessary emissions reductions through enforceable measures. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to the provisions of the rule; additional details regarding the EPA's approach are found in section III of this document.

To apply the first step of the 4-step framework to the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023 and 2026.[11] The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS. This analysis of projected ozone concentrations was then repeated for 2026.

To apply the second step of the framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors.[12] Once quantified, the EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb).[13] States with contributions that equaled or exceeded 1 percent of the NAAQS were identified as warranting further analysis at Step 3 of the 4-step framework to determine if the upwind state significantly contributes to nonattainment or interference with maintenance in a downwind state. States with contributions below 1 percent of the NAAQS were considered not to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states.

Based on the EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA finds that the following 23 states have contributions that equal or exceed 1 percent of the 2015 ozone NAAQS, and, thereby, warrant further analysis of significant contribution to nonattainment or interference with maintenance of the NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

There are locations in California to which Oregon contributes greater than 1 percent of the NAAQS; the EPA

[9] Five of these seven states (Arkansas, Mississippi, Oklahoma, Texas, and Wisconsin) currently participate in the Federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update. The FIPs required under this rule amend the existing FIPs for these states. The other two states (Alabama and Missouri) have already replaced the FIPs finalized in the CSAPR Update with approved SIP revisions that require their EGUs to participate in state Group 2 trading programs integrated with the Federal Group 2 trading program, so the FIPs required in this action constitute new FIPs for these states. The EPA will cease implementation of the state Group 2 trading programs included in the two states' SIPs on the effective date of this rule.

[10] Three states, Kansas, Iowa, and Tennessee, will remain in the Group 2 Trading Program.

[11] These 2 analytic years are the last full ozone seasons before, and thus align with, upcoming attainment dates for the 2015 ozone NAAQS: August 3, 2024, for areas classified as Moderate nonattainment, and August 3, 2027, for areas classified as Serious nonattainment. *See* 83 FR 25776.

[12] The EPA performed air quality modeling for 2032 in the proposed rulemaking, but did not perform contribution modeling for 2032 since contribution data for this year were not needed to identify upwind states to be analyzed in Step 3. The modeling of 2032 done at proposal using the 2016v2 platform does not constitute or represent any final agency determinations respecting air quality conditions or regulatory judgments with respect to good neighbor obligations or any other CAA requirements.

[13] *See* section IV.F of this document for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

proposed that downwind areas represented by these monitoring sites in California should not be considered interstate ozone transport receptors at Step 1. However, the EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

Based on the air quality analysis presented in section IV of this document, the EPA finds that, with the exception of Alabama, Minnesota, and Wisconsin, the states found linked in 2023 will continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season. As a result, the EPA's evaluation of significantly contributing emissions at Step 3 for Alabama, Minnesota, and Wisconsin is limited to emissions reductions achievable by the 2023 and 2024 ozone seasons.

At the third step of the 4-step framework, the EPA applied a multifactor test that incorporates cost, availability of emissions reductions, and air quality impacts at the downwind receptors to determine the amount of ozone precursor emissions from the linked upwind states that ''significantly'' contribute to downwind nonattainment or maintenance receptors. The EPA is applying the multifactor test described in section V.A of this document to both EGU and industrial sources. The EPA assessed the potential emissions reductions in 2023 and 2026,[14] as well as in intervening and later years to determine the emissions reductions required to eliminate significant contribution in 2023 and future years where downwind areas are projected to have potential problems attaining or maintaining the 2015 ozone NAAQS.

For EGU sources, the EPA evaluated the following set of widely-available NO_X emissions control technologies: (1) fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting. For the reasons explained in section V of this document and supported by the ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, EGU NO_X Mitigation Strategies Final Rule TSD'' (Mar. 2023), hereinafter referred to as the EGU NO_X Mitigation Strategies Final Rule TSD, included in the docket for this action, the EPA determines that for the regional, multi-state scale of this rulemaking, only fully operating and optimizing existing SCRs and existing SNCRs (EGU NO_X emissions controls options 1 and 3 in the list earlier) are possible for the 2023 ozone season. The EPA determined that state-of-the-art NO_X combustion controls at EGUs (emissions control option 2 in the list above) are available by the beginning of the 2024 ozone season. *See* section V.B.1 of this document for a full discussion of EPA's analysis of NO_X emissions mitigation strategies for EGU sources.

The EPA is requiring control stringency levels that offer the most incremental NO_X emissions reduction potential from EGUs—among the uniform mitigation measures assessed for the covered region—and the most corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA is making a finding that the required controls provide cost-effective reductions of NO_X emissions that will provide substantial improvements in downwind ozone air quality to address interstate transport obligations for the 2015 ozone NAAQS in a timely manner. These controls represent greater stringency in upwind EGU controls than in the EPA's most recent ozone transport rulemakings, such as the CSAPR Update and the Revised CSAPR Update. However, programs to address interstate ozone transport based on the retrofit of post-combustion controls are by no means unprecedented. In prior ozone transport rulemakings such as the NO_X SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-combustion emissions controls such as SCR.[15] While these programs successfully drove many EGUs to retrofit post-combustion controls, other EGUs throughout the present geography of linked upwind states continue to operate without such controls and continue to emit at relatively high rates more than 20 years after similar units reduced these emissions under prior interstate ozone transport rulemakings.

Furthermore, the CSAPR Update provided only a partial remedy for eliminating significant contribution for the 2008 ozone NAAQS, as needed to obtain available reductions by the 2017 ozone season. In that rule, the EPA made no determination regarding the appropriateness of more stringent EGU NO_X controls that would be required for a *full* remedy for interstate transport for the 2008 ozone NAAQS. Following the remand of the CSAPR Update in *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*), the EPA again declined to require the retrofit of new post-combustion controls on EGUs in the Revised CSAPR Update, but that determination was based on a specific timing consideration: downwind air quality problems under the 2008 ozone NAAQS were projected to resolve before post-combustion control retrofits could be accomplished on a fleetwide, regional scale. *See* 86 FR 23054, 23110 (April 30, 2021).

In this rulemaking, the EPA is addressing good neighbor obligations for the more protective 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in downwind states under that NAAQS. As further discussed in section V of this document, the nature of this contribution warrants a greater degree of control stringency than the EPA determined to be necessary to eliminate significant contribution of ozone transport in prior CSAPR rulemakings. In this rule, the EPA is requiring emissions performance levels for EGU NO_X control strategies commensurate with those determined to be necessary in the NO_X SIP Call and CAIR.

Based on the Step 3 analysis described in section V of this document, the EPA finds that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs within the borders of 22 states linked to downwind

[14] The EPA included emissions reductions from the potential installation of SCRs at all affected large coal-fired EGUs in the 2026 analytic year for the purposes of assessing significant contribution to nonattainment and interference with maintenance, which is consistent with the associated attainment date. However, in response to comments identifying potential supply chain and outage scheduling challenges if the full breadth of these assumed SCR installations were to occur, the EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states.

[15] *See, e.g.,* 70 FR 25162, 25205–06 (May 12, 2005).

nonattainment or maintenance in 2023 (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin). For 19 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal-fired units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal-fired units of less than 100 MW capacity and on CFBs of any capacity size, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NO_X emissions reductions that would result in meaningful air quality improvements in downwind areas, for the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact in providing ozone air quality improvements in affected downwind states. Once the EPA identified the industries, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[16] [17] This information helped shape the proposal and final rule. To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed Reasonably Available Control Technology (RACT) rules, New Source Performance Standards (NSPS) rules, National Emissions Standards for Hazardous Air Pollutants (NESHAP) rules, existing technical studies, rules in approved SIPs, consent decrees, and permit limits. That evaluation is detailed in the ''Technical Support Document (TSD) for the Proposed Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Dec. 2021), hereinafter referred to as the Proposed Non-EGU Sectors TSD, prepared for the proposed FIP.[18]

In this final rule, the EPA is retaining the industries and many of the emissions unit types included in the proposal in its findings of significant contribution at Step 3, as discussed in section V of this document. As discussed in the memorandum for the final rule, titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the Control Measures Database,[19] to estimate NO_X emissions reductions and costs for the year 2026. In this final rule, the EPA made changes to the applicability criteria and emissions limits following consideration of comments on the proposal and reassessed the overall non-EGU emissions reduction strategy based on the factors at Step 3 to render a judgment as to whether the level of emissions control that would be achievable from these units meets the criteria for ''significant contribution.'' In the final rule, we affirm our proposed determinations of which industries and emissions units are potentially impactful and warrant further analysis at Step 3, and we find that the available emissions reductions are cost-effective and make meaningful improvements at the identified downwind receptors. For a detailed discussion of the changes, between the proposal and this final rule, in emissions unit types included and in emissions limits, see section VI.C. of this document.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to evaluate the air quality improvements anticipated to result from the implementation of the selected EGU and non-EGU emissions reduction strategies. See section V.D of this document.[20] We also used AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is a less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that state is linked; or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb) to all of linked receptors. The EPA's over-control analysis, discussed in section V.D.4 of this document, shows that the control stringencies for EGU and non-EGU sources in this final rule do not over-control upwind states' emissions either with respect to the downwind air quality problems to which they are linked or with respect to the 1 percent of the NAAQS contribution threshold, such that over-control would trigger re-evaluation at Step 3 for any linked upwind state.

Based on the multi-factor test applied to both EGU and non-EGU sources and

[16] The memorandum is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150*.

[17] This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that had emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This information helped shape the proposed rule.

[18] The TSD is available in the docket at *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145*.

[19] More information about the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution*.

[20] The use of AQAT and other simplified modeling tools to generate ''appropriately reliable projections of air quality conditions and contributions'' when there is limited time to conduct full-scale photochemical grid modeling was upheld by the D.C. Circuit in *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023). The EPA has used AQAT for the purpose of air quality and overcontrol assessments at Step 3 in the prior CSAPR rulemakings, and we continue to find it reliable for such purposes. We discuss the calibration of AQAT for this action and the multiple sensitivity checks we performed to ensure its reliability in the Ozone Transport Policy Analysis Final Rule TSD in the docket. Because we were able to conduct a photochemical grid modeling run of the 2026 final rule policy scenario, these results are also included in the docket and confirm the regulatory conclusions reached with AQAT. *See* section VIII of this document and Appendix 3A of the Final Rule RIA for more information.

our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 23 upwind states subject to EGU and non-EGU emissions reductions requirements under the rule. For additional details about the multi-factor test and the over-control analysis, *see* the document titled ''Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, Ozone Transport Policy Analysis Proposed Rule TSD'' (Mar. 2023), hereinafter referred to as Ozone Transport Policy Analysis Final Rule TSD, included in the docket for this rulemaking.

In this fourth step of the 4-step framework, the EPA is including enforceable measures in the promulgated FIPs to achieve the required emissions reductions in each of the 23 states. Specifically, the FIPs require covered power plants within the borders of 22 states (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of the following 12 states currently participating in the Group 3 Trading Program will remain in the program, with revised provisions beginning in the 2023 ozone season, under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs within the borders of the following seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period,[21] and affected EGUs within the borders of three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period following the effective date of the final rule. In addition, the EPA is revising other aspects of the Group 3 trading program to better ensure that this method of implementation at Step 4 provides a durable remedy for the elimination of the amount of emissions deemed to constitute significant contribution at Step 3 of the interstate transport framework. These enhancements, summarized later in this section, are designed to operate together to maintain that degree of control stringency over time, thus improving emissions performance at individual units and offering a necessary measure of assurance that NO_X pollution controls will be operated throughout each ozone season, as described in section VI.B of this document. This rulemaking does not revise the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 trading program. Aside from the seven states moving from the Group 2 trading program to the Group 3 trading program under the final rule, this rule otherwise leaves unchanged the budget stringency of the existing CSAPR NO_X Ozone Season Group 2 trading program.

The EPA is establishing preset ozone season NO_X emissions budgets for each ozone season from 2023 through 2029, using generally the same Group 3 trading program budget-setting methodology used in the Revised CSAPR Update, as explained in section VI.B of this document and as shown in Table I.B–1. The preset budgets for the 2026 through 2029 ozone seasons incorporate EGU emissions reductions to eliminate significant contribution and also take into account a substantial number of known retirements over that period to ensure the elimination of significant contribution is maintained as intended by this rule. These budgets serve as floors and may be supplanted by a budget that the EPA calculates for that control period using more recent information (a ''dynamic budget'') if that dynamic budget yields a higher level of allowable emissions—still consistent with the Step 3 level of emissions control stringency—than the preset budget. As reflected in Table I.B–1, and accounting for both the stringency of the rule and known fleet change, the 2026 preset budget is 23 percent lower than the 2025 preset budget; the 2027 preset budget is 20 percent lower than the 2026 preset budget; the 2028 preset budget is 4 percent lower than the 2027 preset budget; and the 2029 preset budget is 8 percent lower than the 2028 preset budget.

While it is possible that additional EGUs may seek to retire in this 2026–2029 period than are currently scheduled and captured in the preset emissions budgets, it is also possible that EGUs with currently scheduled retirements may adjust their retirement timing to accommodate the timing of replacement generation and/or transmission upgrades necessitated by their retirement. While the EPA designed this final rule to provide preset budgets through 2029 to incorporate known retirement-related emissions reductions to ensure the elimination of significant contribution as identified at Step 3 is maintained over time, the use of these floors also provides generators and grid operators enhanced certainty regarding the minimum amount of allowable NO_X emissions for reliability planning through the 2020s. By providing the opportunity for dynamic budgets to subsequently calibrate budgets to any unforeseen increases in fleet demand, it also ensures this rule will not interfere with ongoing retirement scheduling or adjustments and thus is robust to future uncertainty during a transition period.

The EPA also believes the likelihood and magnitude of a scenario in which a state's preset emissions budgets during this period would authorize more emissions than the corresponding dynamic budget is low. As described elsewhere, dynamic budgets are incorporated to best calibrate the rule's stringency to future unknown changes to the fleet. The circumstances in which a dynamic budget would produce a level of allowable emissions less than preset budgets is most pronounced for future periods in which there is a high degree of unknown retirements (increasing the risk that budgets are not appropriately calibrated to the reduced fossil fuel heat input post retirement). However, the 2026–2029 period presents a case where retirement planning has been announced with greater lead time than normal due to a combination of utility 2030 decarbonization commitments, and Effluent Limitation Guideline (ELG) and Coal Combustion Residual (CCR) alternative compliance pathways available to units planning to cease combustion of coal by December 31, 2028. For each of these existing rules, facilities that are planning to retire have already conveyed that intention to EPA in order to take advantage of the alternative compliance pathways

[21] The EPA will deem participation in the Group 3 trading program by the EGUs in these seven states as also addressing the respective states' good neighbor obligations with respect to the 2008 ozone NAAQS (for all seven states), the 1997 ozone NAAQS (for all the states except Texas), and the 1979 ozone NAAQS (for Alabama and Missouri) to the same extent that those obligations are currently being addressed by participation of the states' EGUs in the Group 2 trading program.

available to such facilities.[22] Therefore, the likelihood of unknown retirements—leading to lower dynamic budgets—is much lower than typical for this time horizon. This makes EPA's balanced use of preset emissions budgets or dynamic budgets if they exceed preset levels a reasonable mechanism to accommodate planning and fleet transition dynamics during this period. The need and reasoning for the limited-period preset budget floor is further discussed in section VI.B.4.

For control periods in 2030 and thereafter, the emissions budgets will be the amounts calculated for each state and noticed to the public roughly one year before the control period, using the dynamic budget-setting methodology. In this manner, the stringency of the program will be secured and sustained in the dynamic budgets of this program, regardless of whatever EGU transition activities ultimately occur in this 2026–2029 transition period.

TABLE I.B–1—PRESET CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS (TONS) FOR 2023 THROUGH 2029 CONTROL PERIODS *

State	2023 State budget	2024 State budget	2025 State budget	2026 State budget **	2027 State budget **	2028 State budget **	2029 State budget **
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

* Further information on the state-level emissions budget calculations pertaining to Table I.B–1 is provided in section VI.B.4 of this document as well as the Ozone Transport Policy Analysis Final Rule TSD. Further information on the approach for allocating a portion of Utah's emissions budget for each control period to the existing EGU in the Uintah and Ouray Reservation within Utah's borders is provided in section VI.B.9 of this document.

** As described in section VI of this document, the budget for these years will be subsequently determined and equal the greater of the value above or that derived from the dynamic budget methodology.

The budget-setting methodology that the EPA will use to determine dynamic budgets for each control period starting with 2026 is an extension of the methodology used to determine the preset budgets and will be used routinely to determine emissions budgets for each future control period in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined. The stringency of the dynamic emissions budgets will simply reflect the stringency of the emissions control strategies selected in the rulemaking more consistently over time and ensure that the annual updates would eliminate emissions determined to be unlawful under the good neighbor provision. As already noted, for the control periods in which both preset budgets and dynamic budgets are determined for a state (*i.e.,* 2026 through 2029), the state's dynamic budget will apply only if it is higher than the state's preset budget. *See* section VI.B of this document for additional discussion of the EPA's method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

In conjunction with the levels of the emissions budgets, the carryover of unused allowances for use in future control periods as banked allowances affects the ability of a trading program to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time. Unrestricted banking of allowances allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. To prevent this outcome, the EPA is also revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances using a target percentage of 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years.

As an enhancement to the structure of the trading program originally promulgated in the Revised CSAPR Update, the EPA is also establishing backstop daily emissions rates for coal

[22] Notices of Planned Participation for the ELG Reconsideration Rule were due October 31, 2021 (85 FR 64708, 64679). For the CCR Action, facilities had to indicate their future plans to cease receipt of waste by April 11, 2021 (85 FR 53517).

steam EGUs greater than or equal to 100 MW in covered states. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period.

The backstop daily emissions rates work in tandem with the ozone season emissions budgets to ensure the elimination of significant contribution as determined at Step 3 is maintained over time and more consistently throughout each ozone season. They will offer downwind receptor areas a necessary measure of assurance that they will be protected on a daily basis during the ozone season by more continuous and consistent operation of installed pollution controls. The EPA's experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCRs' performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.[23] In addition to maintaining a mass-based seasonal requirement, this rule will achieve a much more consistent level of emissions control in line with our Step 3 determination of significant contribution while maintaining compliance flexibility consistent with that determination. These trading program improvements will promote consistent emissions control performance across the power sector in the linked upwind states, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

The EPA is including enforceable emissions control requirements that will apply during the ozone season (annually from May to September) for nine non-EGU industries in the promulgated FIPs to achieve the required emissions reductions in 20 states with remaining interstate transport obligations for the 2015 ozone NAAQS in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. These requirements would apply to all existing emissions units and to any future emissions units constructed in the covered states that meet the relevant applicability criteria. Thus, the emissions limitations for non-EGU sources and associated compliance requirements would apply in all 20 states listed in this paragraph, even if some of these states do not currently have any existing emissions units meeting the applicability criteria for the identified industries.

Based on our evaluation of the time required to install controls at the types of non-EGU sources covered by this rule, the EPA has identified the 2026 ozone season as a reasonable compliance date for industrial sources. The EPA is therefore finalizing control requirements for non-EGU sources that take effect in 2026. However, in recognition of comments and additional information indicating that not all facilities may be capable of meeting the control requirements by that time, the final rule provides a process by which the EPA may grant compliance extensions of up to 1 year, which if approved by the EPA, would require compliance no later than the 2027 ozone season, followed by an additional possible extension of up to 2 more years, where specific criteria are met. For sources located in the 20 states listed in the previous paragraph, the EPA is finalizing the NO_X emissions limits listed in Table I.B–2 for reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the NO_X emissions limits listed in Table I.B–3 for kilns in Cement and Cement Product Manufacturing; the NO_X emissions limits listed in Table I.B–4 for reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the NO_X emissions limits listed in Table I.B–5 for furnaces in Glass and Glass Product Manufacturing; the NO_X emissions limits listed in Table I.B–6 for boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and the NO_X emissions limits listed in Table I.B–7 for combustors and incinerators in Solid Waste Combustors or Incinerators.

TABLE I.B–2—SUMMARY OF NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	NO_X emissions limit (g/hp-hr)
Natural Gas Fired Four Stroke Rich Burn	1.0
Natural Gas Fired Four Stroke Lean Burn	1.5
Natural Gas Fired Two Stroke Lean Burn	3.0

TABLE I.B–3—SUMMARY OF NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

[23] *See* 86 FR 23090. The EPA highlighted the Miami Fort Unit 7 (possessing a SCR) more than tripled its ozone-season NO_X emission rate between 2017 and 2019.

Based on evaluation of comments received, the EPA is not, at this time, finalizing the source cap limit as proposed at 87 FR 20046 (*see* section VII.C.2 of the April 6, 2022, Proposal).

TABLE I.B–4—SUMMARY OF NO_X CONTROL REQUIREMENTS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS

Emissions unit	NO_X emissions standard or requirement (lb/mmBtu)
Reheat furnace	Test and set limit based on installation of Low-NO_X Burners.

TABLE I.B–5—SUMMARY OF NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

TABLE I.B–6—SUMMARY OF NO_X EMISSIONS LIMITS FOR BOILERS IN IRON AND STEEL AND FERROALLOY MANUFACTURING, METAL ORE MINING, BASIC CHEMICAL MANUFACTURING, PETROLEUM AND COAL PRODUCTS MANUFACTURING, AND PULP, PAPER, AND PAPERBOARD MILLS

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20
Residual oil	0.20
Distillate oil	0.12
Natural gas	0.08

TABLE I.B–7—SUMMARY OF NO_X EMISSIONS LIMITS FOR COMBUSTORS AND INCINERATORS IN SOLID WASTE COMBUSTORS OR INCINERATORS

Combustor or incinerator, averaging period	NO_X emissions limit (ppmvd)
ppmvd on a 24-hour block averaging period	110
ppmvd on a 30-day rolling averaging period	105

Section VI.C of this document provides an overview of the applicability criteria, compliance assurance requirements, and the EPA's rationale for establishing these emissions limits and control requirements for each of the non-EGU industries covered by the rule.

The remainder of this preamble is organized as follows: section II of this document outlines general applicability criteria and describes the EPA's legal authority for this rule and the relationship of the rule to previous interstate ozone transport rulemakings. Section III of this document describes the human health and environmental challenges posed by interstate transport contributions to ozone air quality problems, as well as the EPA's overall approach for addressing interstate transport for the 2015 ozone NAAQS in this rule. Section IV of this document describes the Agency's analyses of air quality data to inform this rulemaking, including descriptions of the air quality modeling platform and emissions inventories used in the rule, as well as the EPA's methods for identifying downwind air quality problems and upwind states' ozone transport contributions to downwind states. Section V of this document describes the EPA's approach to quantifying upwind states' obligations in the form of EGU NO_X control stringencies and non-EGU emissions limits. Section VI of this document describes key elements of the implementation schedule for EGU and non-EGU emissions reductions requirements, including details regarding the revised aspects of the CSAPR NO_X Group 3 trading program and compliance deadlines, as well as regulatory requirements and compliance deadlines for non-EGU sources. Section VII of this document discusses the environmental justice analysis of the rule, as well as outreach and engagement efforts. Section VIII of this document describes the expected costs, benefits, and other impacts of this rule. Section IX of this document provides a summary of changes to the existing regulatory text applicable to the EGUs covered by this rule; and section X of this document discusses the statutory and executive orders affecting this rulemaking.

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this final rule is presented in Table I.C–1. Table I.C–1 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as recommended by OMB's Circular A–4, of the health and climate benefits, compliance costs, and net benefits of the final rule, in 2016 dollars, discounted to 2023. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the final rule. These results present an incomplete overview of the effects of the rule because important categories of benefits—including benefits from reducing other types of air pollutants, and water pollution—were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the rule to be more net beneficial than this table reflects.

TABLE I.C–1—ESTIMATED MONETIZED HEALTH AND CLIMATE BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULE, 2023 THROUGH 2042

[Millions 2016$, discounted to 2023] [a]

	3% Discount rate	7% Discount rate
Present Value:		
Health Benefits [b]	$200,000	$130,000
Climate Benefits [c]	15,000	15,000
Compliance Costs [d]	14,000	9,400
Net Benefits	200,000	140,000
Equivalent Annualized Value:		
Health Benefits	13,000	12,000
Climate Benefits	970	970
Compliance Costs	910	770
Net Benefits	13,000	12,000

[a] Rows may not appear to add correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. Monetized benefits include those related to public health associated with reductions in ozone and $PM_{2.5}$ concentrations. The health benefits are associated with two point estimates and are presented at real discount rates of 3 and 7 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table.

[c] Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average SC–CO_2 at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.

[d] The costs presented in this table are consistent with the costs presented in Chapter 4 of the *Regulatory Impact Analysis (RIA).* To estimate these annualized costs for EGUs, the EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Costs were calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

As shown in Table I.C–1, the PV of the monetized health benefits, associated with reductions in ozone and $PM_{2.5}$ concentrations, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits, associated with reductions in GHG emissions, of this final rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

II. General Information

A. Does this action apply to me?

This rule affects EGU and non-EGU sources, and regulates the groups identified in Table II.A–1.

TABLE II.A–1—REGULATED GROUPS

Industry group	NAICS
Fossil fuel-fired electric power generation	221112
Pipeline Transportation of Natural Gas	4862
Metal Ore Mining	2122
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221
Solid Waste Combustors and Incinerators	562213

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this rule. This table lists the types of entities that the EPA is now aware could potentially be regulated by this rule. Other types of entities not listed in the table could also be regulated. To determine whether your EGU entity is regulated by this rule, you should carefully examine the applicability criteria found in 40 CFR 97.1004, which are unchanged in this rule. If you have questions regarding the applicability of this rule to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the Agency taking?

The EPA evaluated whether interstate ozone transport emissions from upwind states are significantly contributing to nonattainment, or interfering with maintenance, of the 2015 ozone NAAQS in any downwind state using the same 4-step interstate transport framework that was developed in previous ozone transport rulemakings. The EPA finds that emissions reductions are required from EGU and non-EGU sources in a total of 23 upwind states to eliminate significant contribution to downwind air quality problems for the 2015 ozone standard under the interstate transport provision of the CAA. The EPA will ensure that these NO_X emissions reductions are achieved by issuing FIP requirements for 23 states: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin.

The EPA is revising the existing CSAPR Group 3 Trading Program to include additional states beginning in the 2023 ozone season. EGUs in three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will be added to the CSAPR Group 3 Trading Program under this rule. EGUs in twelve states currently participating in the Group 3 Trading Program will remain in the program under this rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. EGUs in seven states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin) will transition from the CSAPR Group 2 Trading Program to the CSAPR Group 3 Trading Program under this rule beginning in the 2023 ozone season. The EPA is establishing control stringency levels reflecting installation of state-of-the-art combustion controls on certain covered EGU sources in emissions budgets beginning in the 2024 ozone season. The EPA is establishing control stringency levels reflecting installation of new SCR or SNCR controls on certain covered EGU sources in emissions budgets beginning in the 2026 ozone season.

As a complement to the ozone season emissions budgets, the EPA is also establishing a backstop daily emissions rate of 0.14 lb/mmBtu for coal-fired steam units greater than or equal to 100 MW in covered states. The backstop emissions rate will first apply in 2024 for coal-fired steam sources with existing SCRs, and in the second control period in which a new SCR operates, but not later than 2030, for those currently without SCRs.

This rule establishes emissions limitations for non-EGU sources in 20 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. In these states, the EPA is establishing control requirements for the following unit types in non-EGU industries: reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; reheat furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; boilers in Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators. *See* Table II.A–1 in this document for a list of NAICS codes for each entity included for regulation in this rule.

This rule reduces the transport of ozone precursor emissions to downwind areas, which is protective of human health and the environment because acute and chronic exposure to ozone are both associated with negative health impacts. Ozone exposure is also associated with negative effects on ecosystems. Additional information on the air quality issues addressed by this rule are included in section III of this document.

C. What is the Agency's legal authority for taking this action?

The statutory authority for this rule is provided by the CAA as amended (42 U.S.C. 7401 *et seq.*). Specifically, sections 110 and 301 of the CAA provide the primary statutory underpinnings for this rule. The most relevant portions of CAA section 110 are subsections 110(a)(1), 110(a)(2) (including 110(a)(2)(D)(i)(I)) and 110(c)(1)).

CAA section 110(a)(1) provides that states must make SIP submissions ''within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof),'' and that these SIP submissions are to provide for the ''implementation, maintenance, and enforcement'' of such NAAQS.[24] The statute directly imposes on states the duty to make these SIP submissions, and the requirement to make the submissions is not conditioned upon the EPA taking any action other than promulgating a new or revised NAAQS.[25]

The EPA has historically referred to SIP submissions made for the purpose of satisfying the applicable requirements of CAA sections 110(a)(1) and 110(a)(2) as ''infrastructure SIP'' or ''iSIP'' submissions. CAA section 110(a)(1) addresses the timing and general requirements for iSIP submissions, and CAA section 110(a)(2) provides more details concerning the required content of these submissions.[26] It includes a list of specific elements that ''[e]ach such plan'' must address.[27]

CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within 2 years after the Administrator: (1) finds that a state has failed to make a required SIP submission; (2) finds a SIP submission to be incomplete pursuant to CAA section 110(k)(1)(C); or (3) disapproves a SIP submission. This obligation applies unless the state corrects the deficiency through a SIP revision that the Administrator approves before the FIP is promulgated.[28]

CAA section 110(a)(2)(D)(i)(I), also known as the ''good neighbor'' provision, provides the primary basis for this rule.[29] It requires that each state SIP include provisions sufficient to ''prohibit[ ], consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS].'' [30] The EPA often refers to the emissions reduction requirements under this provision as ''good neighbor obligations'' and submissions addressing these requirements as ''good neighbor SIPs.''

[24] 42 U.S.C. 7410(a)(1).

[25] *See EPA* v. *EME Homer City Generation, L.P.*, 572 U.S. 489, 509–10 (2014).

[26] 42 U.S.C. 7410(a)(2).

[27] The EPA's general approach to infrastructure SIP submissions is explained in greater detail in individual notices acting or proposing to act on state infrastructure SIP submissions and in guidance. *See, e.g.,* Memorandum from Stephen D. Page on Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2) (September 13, 2013).

[28] 42 U.S.C. 7410(c)(1).

[29] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[30] *Id.*

Once the EPA promulgates a NAAQS, the EPA must designate areas as being in ''attainment'' or ''nonattainment'' of the NAAQS, or ''unclassifiable.'' CAA section 107(d).[31] For ozone, nonattainment is further split into five classifications based on the severity of the violation—Marginal, Moderate, Serious, Severe, or Extreme. Higher classifications provide states with progressively more time to attain while imposing progressively more stringent control requirements. *See* CAA sections 181, 182.[32] In general, states with nonattainment areas classified as Moderate or higher must submit plans to the EPA to bring these areas into attainment according to the statutory schedule. CAA section 182.[33] If an area fails to attain the NAAQS by the attainment date associated with its classification, it is ''bumped up'' to the next classification. CAA section 181(b).[34]

Section 301(a)(1) of the CAA gives the Administrator the general authority to prescribe such regulations as are necessary to carry out functions under the Act.[35] Pursuant to this section, the EPA has authority to clarify the applicability of CAA requirements and undertake other rulemaking action as necessary to implement CAA requirements. CAA section 301 affords the Agency any additional authority that may be needed to make certain other changes to its regulations under 40 CFR parts 52, 75, 78, and 97, to effectuate the purposes of the Act. Such changes are discussed in section IX of this document.

Tribes are not required to submit state implementation plans. However, as explained in the EPA's regulations outlining Tribal Clean Air Act authority, the EPA is authorized to promulgate FIPs for Indian country as necessary or appropriate to protect air quality if a tribe does not submit, and obtain the EPA's approval of, an implementation plan. *See* 40 CFR 49.11(a); *see also* CAA section 301(d)(4).[36] In the proposed rule, the EPA proposed an ''appropriate or necessary'' finding under CAA section 301(d) and proposed tribal FIP(s) as necessary to implement the relevant requirements. The EPA is finalizing these determinations, as further discussed in section III.C.2 of this document.

D. What actions has the EPA previously issued to address regional ozone transport?

The EPA has issued several previous rules interpreting and clarifying the requirements of CAA section 110(a)(2)(D)(i)(I) with respect to the regional transport of ozone. These rules, and the associated court decisions addressing these rules, summarized here, provide important direction regarding the requirements of CAA section 110(a)(2)(D)(i)(I).

The ''NO_X SIP Call,'' promulgated in 1998, addressed the good neighbor provision for the 1979 1-hour ozone NAAQS.[37] The rule required 22 states and the District of Columbia to amend their SIPs to reduce NO_X emissions that contribute to ozone nonattainment in downwind states. The EPA set ozone season NO_X budgets for each state, and the states were given the option to participate in a regional allowance trading program, known as the NO_X Budget Trading Program.[38] The D.C. Circuit largely upheld the NO_X SIP Call in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), *cert. denied,* 532 U.S. 904 (2001).

The EPA's next rule addressing the good neighbor provision, CAIR, was promulgated in 2005 and addressed both the 1997 fine particulate matter ($PM_{2.5}$) NAAQS and 1997 ozone NAAQS.[39] CAIR required SIP revisions in 28 states and the District of Columbia to reduce emissions of sulfur dioxide (SO_2) or NO_X—important precursors of regionally transported $PM_{2.5}$ (SO_2 and annual NO_X) and ozone (summer-time NO_X). As in the NO_X SIP Call, states were given the option to participate in regional trading programs to achieve the reductions. When the EPA promulgated the final CAIR in 2005, the EPA also issued findings that states nationwide had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 $PM_{2.5}$ and 1997 ozone NAAQS.[40] On March 15, 2006, the EPA promulgated FIPs to implement the emissions reductions required by CAIR.[41] CAIR was remanded to EPA by the D.C. Circuit in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir.), *modified on reh'g,* 550 F.3d 1176 (D.C. Cir. 2008). For more information on the legal issues underlying CAIR and the D.C. Circuit's holding in *North Carolina,* refer to the preamble of the CSAPR rule.[42]

In 2011, the EPA promulgated CSAPR to address the issues raised by the remand of CAIR. CSAPR addressed the two NAAQS at issue in CAIR and additionally addressed the good neighbor provision for the 2006 $PM_{2.5}$ NAAQS.[43] CSAPR required 28 states to reduce SO_2 emissions, annual NO_X emissions, or ozone season NO_X emissions that significantly contribute to other states' nonattainment or interfere with other states' abilities to maintain these air quality standards.[44] To align implementation with the applicable attainment deadlines, the EPA promulgated FIPs for each of the 28 states covered by CSAPR. The FIPs require EGUs in the covered states to participate in regional trading programs to achieve the necessary emissions reductions. Each state can submit a good neighbor SIP at any time that, if approved by EPA, would replace the CSAPR FIP for that state.

CSAPR was the subject of an adverse decision by the D.C. Circuit in August 2012.[45] However, this decision was reversed in April 2014 by the Supreme Court, which largely upheld the rule, including the EPA's approach to addressing interstate transport in CSAPR. *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014) (*EME Homer City I*). The rule was remanded to the D.C. Circuit to consider claims not addressed by the Supreme Court. *Id.* In July 2015 the D.C. Circuit

[31] 42 U.S.C. 7407(d).

[32] 42 U.S.C. 7511, 7511a.

[33] 42 U.S.C. 7511a.

[34] 42 U.S.C. 7511(b).

[35] 42 U.S.C. 7601(a)(1).

[36] 42 U.S.C. 7601(d)(4).

[37] *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone,* 63 FR 57356 (Oct. 27, 1998). As originally promulgated, the NO_X SIP Call also addressed good neighbor obligations under the 1997 8-hour ozone NAAQS, but EPA subsequently stayed and later rescinded the rule's provisions with respect to that standard. *See* 84 FR 8422 (March 8, 2019).

[38] ''Allowance Trading,'' sometimes referred to as ''cap and trade,'' is an approach to reducing pollution that has been used successfully to protect human health and the environment. The design elements of the EPA's most recent trading programs are discussed in section VI.B.1.a of this document.

[39] *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the* NO_X SIP Call, 70 FR 25162 (May 12, 2005).

[40] 70 FR 21147 (April 25, 2005).

[41] 71 FR 25328 (April 28, 2006).

[42] *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals,* 76 FR 48208, 48217 (August 8, 2011).

[43] 76 FR 48208.

[44] CSAPR was revised by several rulemakings after its initial promulgation to revise certain states' budgets and to promulgate FIPs for five additional states addressing the good neighbor obligation for the 1997 ozone NAAQS. *See* 76 FR 80760 (December 27, 2011); 77 FR 10324 (February 21, 2012); 77 FR 34830 (June 12, 2012).

[45] On August 21, 2012, the D.C. Circuit issued a decision in *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012), vacating CSAPR. The EPA sought review with the D.C. Circuit *en banc* and the D.C. Circuit declined to consider the EPA's appeal *en banc. EME Homer City Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir. January 24, 2013), ECF No. 1417012 (denying EPA's motion for rehearing en banc).

generally affirmed the EPA's interpretation of various statutory provisions and the EPA's technical decisions. *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118 (2015) (*EME Homer City II*). However, the court remanded the rule without vacatur for reconsideration of the EPA's emissions budgets for certain states, which the court found may have over-controlled those states' emissions with respect to the downwind air quality problems to which the states were linked. *Id.* at 129–30, 138. For more information on the legal issues associated with CSAPR and the Supreme Court's and D.C. Circuit's decisions in the *EME Homer City* litigation, refer to the preamble of the CSAPR Update.[46]

In 2016, the EPA promulgated the CSAPR Update to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS.[47] The final rule updated the CSAPR ozone season NO_X emissions budgets for 22 states to achieve cost-effective and immediately feasible NO_X emissions reductions from EGUs within those states.[48] The EPA aligned the analysis and implementation of the CSAPR Update with the 2017 ozone season to assist downwind states with timely attainment of the 2008 ozone NAAQS.[49] The CSAPR Update implemented the budgets through FIPs requiring sources to participate in a revised CSAPR NO_X ozone season trading program beginning with the 2017 ozone season. As under CSAPR, each state could submit a good neighbor SIP at any time that, if approved by the EPA, would replace the CSAPR Update FIP for that state. The final CSAPR Update also addressed the remand by the D.C. Circuit of certain states' CSAPR phase 2 ozone season NO_X emissions budgets in *EME Homer City II.*

In December 2018, the EPA promulgated the CSAPR ''Close-Out,'' which determined that no further enforceable reductions in emissions of NO_X were required with respect to the 2008 ozone NAAQS for 20 of the 22 eastern states covered by the CSAPR Update.[50]

The CSAPR Update and the CSAPR Close-Out were both subject to legal challenges in the D.C. Circuit. *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*); *New York* v. *EPA,* 781 Fed. App'x 4 (D.C. Cir. 2019) (*New York*). In September 2019, the D.C. Circuit upheld the CSAPR Update in virtually all respects but remanded the rule because it was partial in nature and did not fully eliminate upwind states' significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS by ''the relevant downwind attainment deadlines'' in the CAA. *Wisconsin,* 938 F.3d at 313–15. In October 2019, the D.C. Circuit vacated the CSAPR Close-Out on the same grounds that it remanded the CSAPR Update in *Wisconsin,* specifically because the Close-Out rule did not address good neighbor obligations by ''the next applicable attainment date'' of downwind states. *New York,* 781 Fed. App'x at 7.[51]

In response to the *Wisconsin* remand of the CSAPR Update and the *New York* vacatur of the CSAPR Close-Out, the EPA promulgated the Revised CSAPR Update on April 30, 2021.[52] The Revised CSAPR Update found that the CSAPR Update was a full remedy for nine of the covered states. For the 12 remaining states, the EPA found that their projected 2021 ozone season NO_X emissions would significantly contribute to downwind states' nonattainment or maintenance problems. The EPA issued new or amended FIPs for these 12 states and required implementation of revised emissions budgets for EGUs beginning with the 2021 ozone season. Based on the EPA's assessment of remaining air quality issues and additional emissions control strategies for EGUs and emissions sources in other industry sectors (non-EGUs), the EPA determined that the NO_X emissions reductions achieved by the Revised CSAPR Update fully eliminated these states' significant contributions to downwind air quality problems for the 2008 ozone NAAQS. As under the CSAPR and the CSAPR Update, each state can submit a good neighbor SIP at any time that, if approved by the EPA, would replace the Revised CSAPR Update FIP for that state.

On March 3, 2023, the D.C. Circuit Court of Appeals denied the Midwest Ozone Group's (MOG) petition for review of the Revised CSAPR Update. *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023). The court noted that it has ''exhaustively'' addressed the interstate transport framework before, citing relevant cases, and ''incorporate them herein by reference.'' Slip Op. 1 n.1. In response to MOG's arguments, the court upheld the Agency's air quality analysis. *Id.* at 10–11. The court noted that in light of the statutory timing framework and court-ordered schedule the EPA was under, the Agency's methodological choices were reasonable and provided ''an appropriately reliable projection of air quality conditions and contributions in 2021.'' *Id.* at 11–12.

III. Air Quality Issues Addressed and Overall Rule Approach

A. The Interstate Ozone Transport Air Quality Challenge

1. Nature of Ozone and the Ozone NAAQS

Ground-level ozone is not emitted directly into the air but is created by chemical reactions between NO_X and volatile organic compounds (VOCs) in the presence of sunlight. Emissions from electric utilities and industrial facilities, motor vehicles, gasoline vapors, and chemical solvents are some of the major sources of NO_X and VOCs.

Because ground-level ozone formation increases with temperature and sunlight, ozone levels are generally higher during the summer months. Increased temperature also increases emissions of volatile man-made and biogenic organics and can also indirectly increase NO_X emissions (*e.g.,* increased electricity generation for air conditioning).

On October 1, 2015, the EPA strengthened the primary and secondary ozone standards to 70 ppb as an 8-hour

[46] *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 81 FR 74504, 74511 (October 26, 2016).

[47] 81 FR 74504.

[48] One state, Kansas, was made newly subject to ozone season NO_X requirements by the CSAPR Update. All other CSAPR Update states were already subject to ozone season NO_X requirements under CSAPR.

[49] 81 FR 74516. The EPA's final 2008 Ozone NAAQS SIP Requirements Rule, 80 FR 12264, 12268 (March 6, 2015), revised the attainment deadline for ozone nonattainment areas designated as Moderate to July 20, 2018. *See* 40 CFR 51.1103. To demonstrate attainment by this deadline, states were required to rely on design values calculated using ozone season data from 2015 through 2017, since the July 20, 2018, deadline did not afford enough time for measured data of the full 2018 ozone season.

[50] *Determination Regarding Good Neighbor Obligations for the 2008 Ozone National Ambient Air Quality Standard,* 83 FR 65878, 65882 (December 21, 2018). After promulgating the CSAPR Update and before promulgating the CSAPR Close-Out, the EPA approved a SIP from Kentucky resolving the Commonwealth's good neighbor obligations for the 2008 ozone NAAQS. 83 FR 33730 (July 17, 2018). In the Revised CSAPR Update, the EPA made an error correction under CAA section 110(k)(6) to convert this approval to a disapproval, because the Kentucky approval relied on the same analysis which the D.C. Circuit determined to be unlawful in the CSAPR Close-Out.

[51] Subsequently, the D.C. Circuit made clear in a decision reviewing the EPA's denial of a petition under CAA section 126 that the holding in *Wisconsin* regarding alignment with downwind area's attainment schedules applies with equal force to the Marginal area attainment date established under CAA section 181(a). *See Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[52] *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 86 FR 23054 (April 30, 2021).

level.[53] Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 70 ppb as a truncated value (*i.e.,* digits to right of decimal removed).[54] In general, areas that exceed the ozone standard are designated as nonattainment areas, pursuant to the designations process under CAA section 107(d), and are subject to heightened planning requirements depending on the severity of their nonattainment classification, *see* CAA sections 181, 182.

In the process of setting the 2015 ozone NAAQS, the EPA noted that the conditions conducive to the formation of ozone (*i.e.,* seasonally-dependent factors such as ambient temperature, strength of solar insolation, and length of day) differ by location, and that the Agency believes it is important that ozone monitors operate during all periods when there is a reasonable possibility of ambient levels approaching the level of the NAAQS. At that time, the EPA stated that ambient ozone concentrations in many areas could approach or exceed the level of the NAAQS, more frequently and during more months of the year compared with the historical ozone season monitoring lengths. Consequently, the EPA extended the ozone monitoring season for many locations. *See* 80 FR 65416 for more details.

Furthermore, the EPA stated that in addition to being affected by changing emissions, future ozone concentrations may also be affected by climate change. Modeling studies in the EPA's Interim Assessment (U.S. EPA, 2009a) that are cited in support of the 2009 Greenhouse Gas Endangerment Finding under CAA section 202(a) (74 FR 66496, Dec. 15, 2009) as well as a recent assessment of potential climate change impacts (Fann et al., 2015) project that climate change may lead to future increases in summer ozone concentrations across the contiguous U.S.[55] (80 FR 65300). The U.S. Global Change Research Program's *Impacts of Climate Change on Human Health in the United States: A Scientific Assessment*[56] and *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II*[57] reinforced these findings. The increase in ozone results from changes in local weather conditions, including temperature and atmospheric circulation patterns, as well as changes in ozone precursor emissions that are influenced by meteorology (Nolte et al., 2018). While the projected impact may not be uniform, climate change has the potential to increase average summertime ozone relative to a future without climate change.[58 59 60] Climate change has the potential to offset some of the improvements in ozone air quality, and therefore some of the improvements in public health, that are expected from reductions in emissions of ozone precursors (80 FR 65300). The EPA responds to comments received on the impacts of climate change on ozone formation in section 11 of the *Response to Comments* (*RTC*) document.

2. Ozone Transport

Studies have established that ozone formation, atmospheric residence, and transport occur on a regional scale (*i.e.,* thousands of kilometers) over much of the U.S.[61] While substantial progress has been made in reducing ozone in many areas, the interstate transport of ozone precursor emissions remains an important contributor to peak ozone concentrations and high-ozone days during the summer ozone season.

The EPA has previously concluded in the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update that a regional NO_X control strategy would be effective in reducing regional-scale transport of ozone precursor emissions. NO_X emissions can be transported downwind as NO_X or as ozone after transformation in the atmosphere. In any given location, ozone pollution levels are impacted by a combination of background ozone concentration, local emissions, and emissions from upwind sources resulting from ozone transport, in conjunction with variable meteorological conditions. Downwind states' ability to meet health-based air quality standards such as the NAAQS is challenged by the transport of ozone pollution across state borders. For example, ozone assessments conducted for the October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone[62] continue to show the importance of NO_X emissions for ozone transport. This analysis is included in the docket for this rulemaking.

Further, studies have found that EGU NO_X emissions reductions can be effective in reducing individual 8-hour peak ozone concentrations and in reducing 8-hour peak ozone concentrations averaged across the ozone season. For example, a study of the EGU NO_X reductions achieved under the NO_X Budget Trading Program (*i.e.,* the NO_X SIP Call) shows that regulating NO_X emissions in that program was highly effective in reducing ozone concentrations during the ozone season.[63]

Previous regional ozone transport efforts, including the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update, required ozone season NO_X reductions from EGU sources to address interstate transport of ozone. Together with NO_X, the EPA has also identified VOCs as a precursor in forming ground-level ozone. Ozone formation chemistry can be ''NO_X-limited,'' where ozone production is primarily determined by the amount of NO_X emissions or ''VOC-limited,'' where ozone production is primarily

[53] 80 FR 65291.

[54] 40 CFR part 50, appendix P.

[55] These modeling studies are based on coupled global climate and regional air quality models and are designed to assess the sensitivity of U.S. air quality to climate change. A wide range of future climate scenarios and future years have been modeled and there can be variations in the expected response in U.S. O3 by scenario and across models and years, within the overall signal of higher summer O3 concentrations in a warmer climate.

[56] U.S. Global Change Research Program (USGCRP), 2016: *The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment.* Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. *https://dx.doi.org/10.7930/J0R49NQX.*

[57] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[58] Fann NL, Nolte CG, Sarofim MC, Martinich J, Nassikas NJ. Associations Between Simulated Future Changes in Climate, Air Quality, and Human Health. JAMA Netw Open. 2021;4(1):e2032064. doi:10.1001/jamanetworkopen.2020.32064

[59] Christopher G Nolte, Tanya L Spero, Jared H Bowden, Marcus C Sarofim, Jeremy Martinich, Megan S Mallard. Regional temperature-ozone relationships across the U.S. under multiple climate and emissions scenarios. J Air Waste Manag Assoc. 2021 Oct;71(10):1251–1264. doi: 10.1080/10962247.2021.1970048.

[60] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4.2018.CH13

[61] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[62] Available in the docket for the October 2015 Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone at *https://www.regulations.gov/docket/EPA-HQ-OAR-2008-0699.*

[63] Butler, et al., ''Response of Ozone and Nitrate to Stationary Source Reductions in the Eastern USA.'' *Atmospheric Environment,* 2011.

determined by the amount of VOC emissions.[64] The EPA and others have long regarded NO_X to be the more significant ozone precursor in the context of interstate ozone transport.[65]

The EPA has determined that the regulation of VOCs as an ozone precursor is not necessary to eliminate significant contribution of ozone transport to downwind areas in this rule. As described in section V.A of this document, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Our analysis of the ozone contribution from upwind states subject to regulation demonstrates that regional ozone concentrations affecting the vast majority of the downwind areas of air quality concern are NO_X-limited, rather than VOC-limited. Therefore, the rule's strategy for reducing regional-scale transport of ozone targets NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas. The potential impacts of NO_X mitigation strategies from other sources are discussed in section V.B of this document.

In section V of this document, the EPA describes the multi-factor test that is used to determine NO_X emissions reductions that are cost-effective and reduce interstate transport of ground-level ozone. Our analysis indicates that the EGU and non-EGU control requirements included in this rule will provide meaningful improvements in air quality at the downwind receptors. Based on the implementation schedule established in section VI.A of this document, the EPA finds that the regulatory requirements included in the rule are as expeditious as practicable and are aligned with the attainment schedule of downwind areas.

3. Health and Environmental Effects

Exposure to ambient ozone causes a variety of negative effects on human health, vegetation, and ecosystems. In humans, acute and chronic exposure to ozone is associated with premature mortality and certain morbidity effects, such as asthma exacerbation. In ecosystems, ozone exposure causes visible foliar injury, decreases plant growth, and affects ecosystem community composition. *See* EPA's October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone[66] in the docket for this rulemaking for more information on the human health and ecosystem effects associated with ambient ozone exposure.

Commenters on prior ozone transport rules have asserted that VOC emissions harm underserved and overburdened communities experiencing disproportionate environmental health burdens and facing other environmental injustices. The EPA acknowledges that VOCs can contain toxic chemicals that are detrimental to public health. The EPA conducted a demographic analysis as part of the regulatory impact analysis for the 2015 revisions to the primary and secondary ozone NAAQS. This analysis, which is included in the docket for this rulemaking, found greater representation of minority populations in areas with poor air quality relative to the revised ozone standard than in the U.S. as a whole. The EPA concluded that populations in these areas would be expected to benefit from implementation of future air pollution control actions from state and local air agencies in implementing the strengthened standard. This rule is an example of air pollution control actions implemented by the Federal Government in support of the more protective 2015 ozone NAAQS, and populations living in downwind ozone nonattainment and maintenance areas are expected to benefit from improved air quality that will result from reducing ozone transport. Further discussion of the environmental justice analysis of this rule is located in section VII of this document and in the accompanying regulatory impact analysis, titled ''Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452/D–22–001], which is available in the docket for this rulemaking.

The Agency regulates exposure to toxic pollutant concentrations and ambient exposure to criteria pollutants other than ozone through other sections of the Act, such as the regulation of hazardous air pollutants under CAA section 112 or the process for revising and implementing the NAAQS under CAA sections 107–110. The purpose of the subject rulemaking is to protect public health and the environment by eliminating significant contribution from 23 states to nonattainment or maintenance of the 2015 ozone NAAQS to meet the requirements of the CAA's interstate transport provision. In this rule, the EPA continues to observe that requiring NO_X emissions reductions from stationary sources is an effective strategy for reducing regional ozone transport in the U.S.

The EPA responds to other comments received on the health and environmental impacts of ozone exposure in section 11 of the *RTC* document.

B. Final Rule Approach

1. The 4-Step Interstate Transport Framework

The EPA first developed a multi-step process to address the requirements of the good neighbor provision in the 1998 NO_X SIP Call and the 2005 CAIR. The Agency built upon this framework and further refined the methodology for addressing interstate transport obligations in subsequent rules such as CSAPR in 2011, the CSAPR Update in 2016, and the Revised CSAPR Update in 2021.[67] In CSAPR, the EPA first articulated a ''4-step framework'' within which to assess interstate transport obligations for ozone. In this rule to address interstate transport obligations for the 2015 ozone NAAQS, the EPA is again utilizing the 4-step interstate transport framework. These steps are: (1) identifying downwind receptors that are expected to have problems attaining the NAAQS (nonattainment receptors) or maintaining the NAAQS (maintenance receptors); (2) determining which upwind states are ''linked'' to these identified downwind receptors based on a numerical contribution threshold; (3) for states linked to downwind air quality problems, identifying upwind emissions on a statewide basis that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS, considering cost- and air quality-based factors; and (4) for upwind states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, implementing the necessary emissions reductions through enforceable measures.

Comment: The EPA received comments supporting the Agency's use of the 4-step interstate transport framework as a permissible method for assigning the required amount of

[64] ''Ozone Air Pollution.'' *Introduction to Atmospheric Chemistry,* by Daniel J. Jacob, Princeton University Press, Princeton, New Jersey, 1999, pp. 231–244.

[65] 81 FR 74514.

[66] Available at *https://www.epa.gov/sites/default/files/2016-02/documents/20151001ria.pdf.*

[67] *See* CSAPR, Final Rule, 76 FR 48208, 48248–48249 (August 8, 2011); CSAPR Update, Final Rule, 81 FR 74504, 74517–74521 (October 26, 2016).

emissions reductions necessary to eliminate upwind states' significant contribution. Commenters also noted that the 4-step interstate transport framework was reviewed by the Supreme Court in *EPA vs. EME Homer City Generation,* 572 U.S. 489 (2014), and upheld. However, other commenters took exception to the overall approach of this proposed action. These commenters alleged that the EPA is ignoring the ''flexibility'' in addressing good neighbor obligations that it had purportedly suggested to states would be permissible in memoranda that the EPA issued in 2018. Commenters also raised concerns that the air quality modeling (2016v2) the EPA used to propose to disapprove SIP submittals and as the basis for the proposed FIP was not available to states at the time they made their submissions and that the changes in results at Steps 1 and 2 from prior rounds of modeling rendered the new modeling unreliable. Commenters also raised a number of arguments that the EPA should allow states an additional opportunity to submit SIPs before promulgating a FIP, advocated that the EPA should issue a ''SIP call'' under CAA section 110(k)(5), asked for the EPA to issue new or more specific guidance, or otherwise suggested that the EPA should defer acting to promulgate a FIP at this time.

Response: As an initial matter, comments regarding the EPA's basis for disapproving SIPs are beyond the scope of this action.[68] To the extent these comments relate to the legal basis for the EPA to promulgate a FIP, the EPA disagrees that it is acting in a manner contrary to the memoranda it released in 2018 related to good neighbor obligations for the 2015 ozone NAAQS. Arguments that the EPA must or should allow states to re-submit SIP submissions based on the most recent modeling information before the EPA promulgates a FIP ignore the plain language of the statute and relevant caselaw. CAA section 110(c) authorizes the EPA to promulgate a FIP ''at any time within 2 years'' of a SIP disapproval. No provision of the Act requires the EPA to give states an additional opportunity to prepare a new SIP submittal once the EPA has proposed a FIP or proposed disapproval of a SIP submittal. Comments regarding the timing of the EPA's actions and calls for the EPA to allow time for states to resubmit SIPs are further addressed in *RTC* sections 1.1 and 2.4.

With regard to the need for the EPA to develop and issue guidance in addressing good neighbor obligations, in *EPA* v. *EME Homer City Generation, L.P.,* the Supreme Court held that ''nothing in the statute places the EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.''[69] While we have taken a different approach in some prior rulemakings by providing states with an opportunity to submit a SIP after we quantified the states' budgets (*e.g.,* the NO_X SIP Call and CAIR[70]), the CAA does not require such an approach.

2018 Memoranda. As commenters point out, the EPA issued three ''memoranda'' in 2018 to provide some assistance to states in developing these SIP submittals.[71] Each memorandum made clear that the EPA's action on SIP submissions would be through a separate notice-and-comment rulemaking process and that SIP submissions seeking to rely on or take advantage of any so-called ''flexibilities'' in these memoranda would be carefully reviewed against the relevant legal requirements and technical information available to the EPA at the time it would take such rulemaking action. Further, certain aspects of discussions in those memoranda were specifically identified as not constituting agency guidance (especially Attachment A to the March 2018 memorandum, which comprised an unvetted list of external stakeholders' ideas). And, although outside the scope of this action, as the EPA has explained in disapproving states' SIP submittals, those submittals did not meet the terms of the August 2018 or October 2018 memoranda addressing contribution thresholds and maintenance receptors, respectively.

Commenters mistakenly view Attachment A to the March 2018 memorandum as constituting agency guidance. This memorandum was primarily issued to share modeling results for 2023 that represented the best information available to the Agency as of March 2018, while Attachment A then listed certain ideas from certain stakeholders that the EPA said could be further discussed among states and stakeholders. The EPA disagrees with commenters' characterization of the EPA's stance regarding these so-called ''flexibilities'' listed (without analysis) in Attachment A. The March 2018 memorandum provided, ''While the information in this memorandum and the associated air quality analysis data could be used to inform the development of these SIPs, the information is not a final determination regarding states' obligations under the good neighbor provision.'' The EPA again affirms that the concepts listed in Attachment A to the March 2018 memorandum require unique consideration, and these ideas do not constitute agency guidance with respect to transport obligations for the 2015 ozone NAAQS. Attachment A to the March 2018 memorandum identified a ''Preliminary List of Potential Flexibilities'' that could potentially inform SIP development. However, the EPA made clear in both the March 2018 memorandum[72] and in Attachment A that the list of ideas was not endorsed by the Agency but rather ''comments provided in various forums'' on which the EPA sought ''feedback from interested stakeholders.''[73] Further, Attachment A stated, ''EPA is not at this time making any determination that the ideas discussed below are consistent with the requirements of the CAA, nor are we specifically recommending that states use these approaches.''[74] Attachment A to the March 2018 memorandum, therefore, does not

[68] We nonetheless further respond to comments regarding the timing and sequence of the EPA's SIP and FIP actions, the relevance of judicial consent decrees, the requests for a SIP call, and related comments—to the extent any of these issues are within scope of the present action—in Sections 1 and 2 of the *RTC* document located in the docket for this action.

[69] 572 U.S. 489, 510 (2014). ''Nothing in the Act differentiates the Good Neighbor Provision from the several other matters a State must address in its SIP. Rather, the statute speaks without reservation: Once a NAAQS has been issued, a State 'shall' propose a SIP within three years, § 7410(a)(1), and that SIP 'shall' include, among other components, provisions adequate to satisfy the Good Neighbor Provision, § 7410(a)(2).'' *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. at 515.

[70] For information on the NO_X SIP call see 63 FR 57356 (October 27, 1998). For information on CAIR *see* 70 FR 25162 (May 12, 2005).

[71] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I) (March 27, 2018) (''March 2018 memorandum''); Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, August 31, 2018) (''August 2018 memorandum''); Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''). These are available in the docket or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.*

[72] ''In addition, the memorandum is accompanied by Attachment A, which provides a preliminary list of potential flexibilities in analytical approaches for developing a good neighbor SIP that may warrant further discussion between EPA and states.'' March 2018 memorandum at 1.

[73] March 2018 memorandum, Attachment A at A–1.

[74] *Id.*

constitute agency guidance, but was intended to generate further discussion around potential approaches to addressing ozone transport among interested stakeholders. The EPA emphasized in these memoranda that such alternative approaches must be technically justified and appropriate in light of the facts and circumstances of each particular state's submittal. To the extent states sought to develop or rely on one or more of these ideas in support of their SIP submissions, the EPA reviewed their technical and legal justifications for doing so.[75]

Regarding the October 2018 memorandum, that document recognized that states may be able to demonstrate in their SIPs that conditions exist that would justify treating a monitoring site as not being a maintenance receptor despite results from our modeling methodology identifying it as such a receptor. The EPA explained that this demonstration could be appropriate under two circumstances: (1) the site currently has ''clean data'' indicating attainment of the 2015 ozone NAAQS based on measured air quality concentrations, or (2) the state believes there is a technical reason to justify using a design value from the baseline period that is lower than the maximum design value based on monitored data during the same baseline period. To justify such an approach, the EPA anticipated that any such showing would be based on an analytical demonstration that (1) meteorological conditions in the area of the monitoring site were conducive to ozone formation during the period of clean data or during the alternative base period design value used for projections; (2) ozone concentrations have been trending downward at the site since 2011 (and ozone precursor emissions of NO_X and VOC have also decreased); and (3) emissions are expected to continue to decline in the upwind and downwind states out to the attainment date of the receptor. Although this is beyond the scope of this action, the EPA explained in its final SIP disapproval action that no state successfully demonstrated that one of these alternative approaches is justified. In this action, our analysis of the air quality data and projections in section IV of this document indicate that trends in historic measured data do not necessarily support adopting a less stringent approach for identifying maintenance receptors for purposes of the 2015 ozone NAAQS. In fact, as explained in section III.B.1.a and IV.D of this document, the EPA has found in its analysis for this final rule that, in general, recent measured data from regulatory ambient air quality ozone monitoring sites suggest that a number of receptors with elevated ozone levels will persist in 2023 even though our traditional methodology at Step 1 did not identify these monitoring sites as receptors in 2023. Thus, the EPA is not acting inconsistently with that memorandum—the factual conditions that would need to exist for the suggested approaches of that memorandum to be applicable have not been demonstrated as being applicable or appropriate based on the relevant data.

Regarding the August 2018 memorandum, as discussed in section IV.F.2 of this document, for purposes of Step 2 of our ozone transport evaluation framework, we are applying a 1 percent of NAAQS threshold rather than a 1 ppb threshold, as this memorandum had suggested might be appropriate for states to apply as an alternative. The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS contribution threshold at Step 2 to evaluate whether states are linked to downwind nonattainment and maintenance concerns for purposes of this FIP.

The approach of this FIP ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. Further, in this action the EPA is promulgating FIPs under the authority of CAA section 110(c). In doing so, the EPA has exercised its discretion to determine how to define and apply good neighbor obligations in place of the discretion states otherwise would exercise (subject to the EPA's approval as compliant with the Act). In general, the EPA is applying the 4-step interstate transport framework it devised over the course of its prior good neighbor rulemakings, including applying a consistent definition of nonattainment and maintenance-only receptors, and applying the 1 percent of NAAQS threshold at Step 2. The basis for these decisions is further explained in sections IV.F.1 and IV.F.2 of the document. These policy judgments reflect consistency with relevant good neighbor case law and past agency practice implementing the good neighbor provision as reflected in the original CSAPR, CSAPR Update, Revised CSAPR Update, and related rulemakings. Nationwide consistency in approach is particularly important in the context of interstate ozone transport, which is a regional-scale pollution problem involving the collective emissions of many smaller contributors. Effective policy solutions to the problem of interstate ozone transport dating back to the NO_X SIP Call (63 FR 57356 (October 27, 1998)) have necessitated the application of a uniform framework of policy judgments, and the EPA's framework applied here has been upheld as ensuring an ''efficient and equitable'' approach. *See EME Homer City Generation, LP* v. *EPA,* 572 U.S. 489, 519 (2014).

Updated modeling. The EPA had originally provided 2023 modeling results in its March 2018 memorandum, which used a 2011-based platform. Many states used this modeling in providing good neighbor SIP submittals for the 2015 ozone NAAQS. While our action on the SIP submittals is not within scope of this action, commenters claim the use of new modeling or other information not available to states at the time they made their submittals renders this action promulgating a FIP unlawful. Notwithstanding whether that is an accurate characterization of the EPA's basis for disapproving the SIPs, we note that the court in *Wisconsin* rejected this precise argument against the CSAPR Update FIPs as a collateral attack on the SIP disapprovals. 938 F.3d at 336 (''That is the hallmark of an improper collateral attack. The true gravamen of the claim lies in the agency's failure to timely act upon the States' SIP submissions and, relatedly, its reliance on data compiled after the SIP action deadline. Both go directly to the legitimacy of the SIP denials.'').

Nonetheless, we offer the following explanation of the evolution of the EPA's understanding of projected air quality conditions and contributions in 2023 resulting from the iterative nature of our modeling efforts. These modeling efforts are further addressed in section IV of this document. We acknowledge that to evaluate transport SIPs and support our proposed FIP the EPA reassessed receptors at Step 1 and states' contribution levels at Step 2 through additional modeling (2016v2) before proposing this action and have reassessed again to inform the final action (2016v3). At proposal, we relied on CAMx Version 7.10 and the 2016v2 emissions platform to make updated determinations regarding which receptors would likely exist in 2023 and which states are projected to contribute above the contribution threshold to those receptors. As explained in the preamble of the EPA's proposed FIP and further detailed in the ''Air Quality

[75] *E.g.*, 87 FR 64423–64425 (Alabama); 87 FR 31453–31454 (California); 87 FR 9852–9854 (Illinois); 87 FR 9859–9860 (Indiana); 87 FR 9508, 9515 (Kentucky); 87 FR 9861–9862 (Michigan); 87 FR 9869–9870 (Ohio); 87 FR 9798, 9818–9820 (Oklahoma); 87 FR 31477–31481 (Utah); 87 FR 9526–9527 (West Virginia).

Modeling Technical Support Document for the Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards Proposed Rulemaking'' (Dec. 2021), hereinafter referred to as Air Quality Modeling Proposed Rule TSD, and the ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform'' (Dec. 2021), hereinafter referred to as the 2016v2 Emissions Inventory TSD, both available in the docket for this action (docket ID no. EPA–HQ–OAR–2021–0668), this modeling built off of previous modeling iterations used to support the EPA's action on interstate transport obligations. The EPA periodically refines its modeling to ensure the results are as indicative as possible of air quality in future years. This includes making any necessary adjustments to our modeling platform and updating our emissions inventories to reflect current information, including information submitted during public comments on proposed actions.

For this final rule, the EPA has evaluated a raft of technical information and critiques of its 2016v2 modeling provided by commenters on this action (as well as comments on the SIP actions) and has responded to those comments and incorporated updates into the version of the modeling used to support this final rule (2016v3). As explained in section IV.B of the document, in response to additional information provided by stakeholders following a solicitation of feedback during the release of the 2016v2 emissions inventory and during the comment periods on the proposed SIP actions, the EPA has reviewed and revised its 2016v2 modeling platform and input since the platform was made available for comment. The new modeling platform 2016v3 was developed from this input, and the modeling results using platform 2016v3 are available with this action. *See* section IV of this document for further discussion. Thus, the EPA's final rule is based on a comprehensive record of data and technical evaluation, including the updated modeling information used at proposal (2016v2), the comments received on that modeling, and the latest modeling used in this final rule (2016v3).

The changes in projected outcomes at Steps 1 and 2 are a product of these changes; these updates between the data released in 2018 to now are an outgrowth of this iterative process, including updating the platform from a 2011 to a 2016 base year, updates to the emissions inventory information and other updates. It is reasonable for the Agency to improve its understanding of a situation before taking final action, and the Agency uses the best information available to it in taking this action.

Further, these modeling updates have not uniformly resulted in new linkages—the 2016v2 modeling, for instance, corroborated the proposed approval of Montana and supported approval of Colorado's SIP in October of 2022.[76] Although some commenters indicate that our modeling iterations have provided differing outcomes and are therefore unreliable, this is not what the overall record indicates. Rather, in general, although the specifics of states' linkages may have changed to some extent, our modeling on the whole has provided consistent outcomes regarding which states are linked to downwind air quality problems. For example, the EPA's modeling shows that most states that were linked to one or more receptors using the 2011-based platform (*i.e.,* the March 2018 data release) are also linked to one or more receptors using the newer 2016-based platform. Because the new platform uses different meteorology (*i.e.,* 2016 instead of 2011), it is not unexpected that an upwind state would be linked to different receptors using 2011 versus 2016 meteorology. In addition, although a state may be linked to a different set of receptors, those receptors are within the same areas that have historically had a persistent air quality problem. Only three upwind states included in the FIP went from being unlinked to being linked in 2023 between the 2011-based modeling provided in the March 2018 memorandum and the 2016v3-based modeling—Alabama, Minnesota, and Nevada.

Additionally, we disagree with commenters who claim that the 2016v2 modeling results were sprung upon the states with the publication of the proposed SIP disapprovals. In fact, states had prior access to a series of data and modeling releases beginning as early as the publication of the 2016v1 modeling with the proposed Revised CSAPR Update in October 2020. States could have reviewed and used this technical information to understand and track how the EPA's modeling updates were affecting the list of potential receptors and linkages for the 2015 ozone NAAQS in the 2023 analytic year.

The 2016-based meteorology and boundary conditions used in the modeling have been available through the 2016v1 platform, which was used for the Revised CSAPR Update (proposed, 85 FR 68964; October 30, 2020). The updated emissions inventory files used in the current modeling were publicly released September 21, 2021, for stakeholder feedback, and have been available on our website since that time.[77] The CAMx modeling software that the EPA used has likewise been publicly available for over a year before this final rule was proposed on April 6, 2022. CAMx version 7.10 was released by the model developer, Ramboll, in December 2020. On January 19, 2022, we released on our website and notified a wide range of stakeholders of the availability of both the modeling results for 2023 and 2026 (including contribution data) along with many key underlying input files.[78]

By providing the 2016 meteorology and boundary conditions (used in the 2016v1 version) in fall of 2020, and by releasing updated emissions inventory information used in 2016v2 in September of 2021,[79] we gave states and other interested parties multiple opportunities prior to proposal of this rule on April 6, 2022, to consider how our modeling updates could affect their status for purposes of evaluating potential linkages for the 2015 ozone NAAQS. In this final rule, we have updated our modeling to 2016v3, incorporating and reflecting the feedback and additional information we received through the multiple public comment opportunities the EPA made available on the 2016v2 modeling.

The EPA's development of and reliance on newer modeling is reasonable and is simply another iteration of the EPA's longstanding scientific and technical work to improve our understanding of air quality issues and causes going back many decades.

Comment: Commenters asserted that the EPA lacks authority under the good neighbor provision to do more than establish state-wide emissions budgets, which states may then implement through their own choice of emissions controls. The commenters claim that the EPA lacks authority to directly regulate emissions sources under the good neighbor provision, and they cite to case law that they view as establishing a ''federalism bar'' to direct Federal regulation. Commenters assert that the

[76] 87 FR 6095, 6097 at n. 15 (February 3, 2022) (Montana proposal); 87 FR 27050, 27056 (May 6, 2022) (Colorado, proposal), 87 FR 61249 (October 11, 2022) (Colorado, final).

[77] *See https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

[78] *See https://www.epa.gov/scram/photochemical-modeling-applications.*

[79] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

term ''amounts'' as used in the good neighbor provision prevents the agency from establishing emissions limits at individual sources, such as the non-EGU industrial units that the EPA proposed to regulate or implementing ''enhancements'' in its mass-based emissions trading approach for EGUs as it had proposed. Commenters claim these aspects of the rule are an unlawful or arbitrary and capricious departure from the EPA's prior transport rulemakings, which they claim only set mass-based emissions budgets as the means to eliminate ''significant contribution.''

Response: To the extent these comments challenge the EPA's disapproval of states' 2015 ozone NAAQS good neighbor SIP submissions, they are out of scope of this action, which promulgates a FIP under the authority of CAA section 110(c)(1). To the extent commenters assert that the EPA does not have the authority to directly implement source-specific emissions control requirements or other emissions control measures, means, or techniques, including emissions trading programs, in the exercise of that FIP authority, the EPA disagrees. While the courts have long recognized that the states have wide discretion in the design of SIPs to attain and maintain the NAAQS, *see, e.g., Union Electric Co* v. *EPA,* 427 U.S. 246 (1976), when the EPA promulgates a FIP to cure a defective SIP, the Act, including the definition of a FIP in section 302(y), provides for the EPA to directly implement the Act's requirements. The EPA is granted authority to choose among a broad range of ''emission limitations or other control measures, means, or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances) . . . .'' CAA section 302(y); *see also* CAA section 110(a)(2) (empowering states to implement an identical set of emissions control mechanisms).

The courts have also recognized that the EPA has broad authority to cure a defective SIP, that the EPA may exercise its own, independent regulatory authority in implementing a FIP in accordance with the CAA, and that the EPA in effect steps into the shoes of a state when it promulgates a FIP. *See, e.g., Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531 (9th Cir. 1993); *South Terminal Corp.* v. *EPA,* 504 F.2d 646 (1st Cir. 1974). *Accord Virginia* v. *EPA,* 108 F.3d 1397, 1406–07 (D.C. Cir. 1997) (''The Federal Plan 'provides an additional incentive for state compliance because it rescinds state authority to make the many sensitive and policy choices that a pollution control regime demands.''') (quoting *Natural Resources Defense Council* v. *Browner,* 57 F.3d 1122, 1124 (D.C. Cir. 1995)). *Cf. District of Columbia* v. *Train,* 521 F.2d 971 (D.C. Cir. 1975), *vacated sub nom. EPA* v. *Brown,* 431 U.S. 99 (1977) (''[W]here cooperation [from states] is not forthcoming, we believe that the recourse contemplated by the commerce clause is direct federal regulation of the offending activity . . . .'').

These same principles apply where the EPA must promulgate a FIP to address good neighbor requirements under CAA section 110(a)(2)(D)(i)(I). The EPA has promulgated a series of FIPs in the past to address the relevant requirements for prior ozone and PM NAAQS. *See, e.g.,* CAIR FIP, 71 FR 25328 (April 28, 2006); CSAPR, 76 FR 48208 (August 8, 2011); the CSAPR Update, 81 FR 74504 (October 26, 2016); and the Revised CSAPR Update, 86 FR 23054 (April 30, 2021). Courts have upheld the EPA's exercise of this authority. *See EME Homer City Generation* v. *EPA,* 572 U.S. 489 (2014); *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019). Indeed, in *EME Homer City,* the U.S. Supreme Court held that the EPA is not obligated to provide guidance to states before acting on their good neighbor submissions or give states a second chance at correcting the deficiencies before promulgating a FIP, and the EPA may promulgate a FIP at any time after finalizing its disapproval of SIP submissions. 572 U.S. at 508–11.

The cases cited by commenters, which they refer to as establishing the *Train-Virginia* federalism bar, were not reviewing the exercise of the EPA's authority in promulgating a FIP under CAA section 110(c)(1) but rather were describing the scope of the EPA's authority in acting on SIP submissions under CAA section 110(k)(3) or in issuing a ''SIP call'' under section 110(k)(5). In those latter contexts, the courts have held that the EPA may not dictate the specific control measures states must implement to meet the Act's requirements. *See Virginia,* 108 F.3d at 1409–10. In *Michigan,* the D.C. Circuit upheld the EPA's exercise of CAA section 110(k)(5) authority in issuing the ''NO_X SIP Call,'' because, ''EPA does not tell the states how to achieve SIP compliance. Rather, EPA looks to section 110(a)(2)(D) and merely provides the levels to be achieved by state-determined compliance mechanisms. . . . However, EPA made clear that states do not have to adopt the control scheme that EPA assumed for budget-setting purposes.'' *Michigan* v. *EPA,* 213 F.3d 663, 687–88 (D.C. Cir. 2000).

Commenters' position that the EPA must provide similar flexibility to the states in this action (*i.e.,* only provide a general emissions reduction target and leave to states how to meet that target) is a non sequitur. The EPA is implementing a FIP in this action and *must* directly implement the necessary emissions controls. The EPA is not empowered to require states to implement FIP mandates. Such an approach would conflict with constitutional anti-commandeering principles, is not provided for in the Act, and would only constitute a partial implementation of FIP obligations in contravention of the holding in *Wisconsin* v. *EPA,* 938 F.3d at 313–20.

Commenters' attempt to contrast the implementation of source-specific emissions limitations at industrial sources with the establishment of a specific mass-based budget (as the EPA has set for power plants in prior good neighbor FIPs) is unavailing. CAA section 110(c)(1) and 302(y) authorize the EPA in promulgating a FIP to establish ''enforceable emission limitations'' in addition to other types of control measures like mass-based trading programs. Further, in this action, the EPA has developed an emissions control strategy that prohibits the ''amount'' of pollution that significantly contributes to nonattainment and/or interferes with maintenance. We determine that amount, as we have in prior transport actions, at Step 3 of the analysis, by applying a multifactor analysis that includes considering cost and downwind air quality effects. *See* section V.A of this document. With the implementation of the selected controls (at Step 4) through both an emissions trading program for power plants and source-specific emissions limitations for industrial sources, those ''amounts'' that had been emitted prior to imposition of the controls will be eliminated.

The Act does not mandate that the EPA must set a specific mass-based budget for each state to eliminate significant contribution based on the use of the term ''amounts'' in CAA section 110(a)(2)(D)(i). As the Supreme Court recognized, the statute ''*requires* States to eliminate those 'amounts' of pollution that 'contribute significantly to nonattainment' in downwind States,'' and it delegates to states or EPA acting in their stead discretion to determine *how* to apportion responsibility among those upwind states. 572 U.S. at 514 (emphasis added). The statute does not define the term ''amount'' in the way commenters suggest (or in any other way), and neither the Agency nor any court has reached that conclusion. The

Supreme Court itself has recognized that the language of the good neighbor provision is amenable to different types of metrics for quantification of ''significant contribution.'' *See EME Homer City Generation, L.P.,* 572 U.S. at 514 (''How is EPA to divide responsibility among the . . . States? Should the Agency allocate reductions proportionally . . ., on a per capita basis, on the basis of the cost of abatement, or by some other metric? . . . The Good Neighbor Provision does not answer that question for EPA.''); *see also Michigan* v. *EPA,* 213 F.3d 663, 677 D.C. Cir. 2000) (''Nothing in the text of . . . the statute spells out a criterion for classifying 'emissions activity' as 'significant.' ''); *id.* at 677 (''Must EPA simply pick some flat 'amount' of contribution . . . ?''). When the State of Delaware petitioned the Agency under CAA section 126(b) to establish daily emissions rates for EGUs to remedy what it saw as continuing violations of the good neighbor provision for the 2008 ozone NAAQS, neither the EPA nor the reviewing court questioned whether the Agency had the statutory authority to do so. The EPA's decision not to was upheld on record grounds. *See Maryland* v. *EPA,* 958 F.3d 1185, 1207 D.C. Cir. 2020) (''In other words, Delaware's concern makes sense but has not been observed in practice.'').[80]

The term ''amounts'' can be interpreted to refer to any number of metrics, and in fact the CAA uses the term in several contexts where it is clear Congress did not intend the term to refer to a fixed, mass-based quantity of emissions. For example, in the definition of ''lowest achievable emission rate'' (LAER) in CAA section 171, the Act provides that the application of LAER shall not permit a proposed new or modified source to emit any pollutant in excess of ''the amount allowable under applicable new source standards of performance [NSPS].'' NSPS may be, and usually are, set as emissions standards or limitations that are rate- or concentration-based. *See, e.g.,* 40 CFR part 60, subpart KKKK, table I (establishing concentration-based and rate-based emissions limits for stationary combustion turbines).[81] Congress has elsewhere used the term ''amount'' in the CAA to refer to concentration-based standards. For example, in CAA section 163(b), Congress provided that maximum allowable increases in concentrations of certain pollutants ''shall not exceed the following amounts,'' with a list of allowable increases provided that are expressed in micrograms per cubic meter.[82] As a third example, in the 1990 CAA Amendments, Congress provided that ozone nonattainment areas classified as Serious must provide a reasonable further progress demonstration of reductions in VOC emissions ''equal to the following amount,'' which is then described as a percentage reduction from baseline emissions. CAA section 182(c)(2)(B). These examples illustrate that the word ''amounts'' is amenable to a variety of meanings depending on what is being measured or quantified. It would therefore be highly unlikely that Congress could have intended that ''amount'' as used in the good neighbor provision must signify only a fixed mass budget of emissions for each state expressed as total tons per ozone season.

Such an approach would, in fact, fail to address an important aspect of the problem of interstate transport. As explained in sections III.B.1.d, V.D.4, and VI.B.1, the EPA in this rule seeks to better address the need for emissions reductions on each day of the ozone season, reflecting the daily, but unpredictably recurring, nature of the air pollution problem, short-term health impacts, and the form of the 2015 ozone NAAQS, wherein nonattainment for downwind areas (and thus heightened regulatory requirements) could be based on ozone exceedances on just a few days of the year. The expression of the ''amount'' of pollution that should be eliminated to address upwind states' ''significant contribution'' to that type of air pollution problem may appropriately take into account those aspects of the problem, and the EPA may appropriately conclude, as we do here, that a single, fixed, emissions budget covering an entire ozone season is not sufficient to the task at hand.

In this action, the EPA reasonably applies the good neighbor provision, including the term ''amount,'' through the 4-step interstate transport framework. Under this approach, the EPA here, as it has in prior transport rulemakings for regional pollutants like ozone, identifies a uniform level of emissions reduction that the covered sources in the linked upwind states can achieve that cost-effectively delivers improvement in air quality at downwind receptors on a regional scale. The ''amount'' of pollution that is identified for elimination at Step 3 of the framework is therefore that amount of emissions that is in excess of the emissions control strategies the EPA has deemed cost-effective. Contrary to commenters' views, in prior transport rules utilizing emissions trading, the mass budgets through which the elimination of significant contribution was effectuated did not constitute the ''amounts'' to be eliminated but rather the residual emissions remaining following the elimination of significant contribution through the control stringency selected based on our multifactor assessment at Step 3. Nor did the EPA consider a mass-based budget to be the sole expression, even indirectly, of what constituted ''significant contribution.'' *See, e.g.,* CSAPR, 76 FR 48256–57 (discussing the evaluation of the control strategies that would eliminate significant contribution for the 1997 ozone NAAQS, including combustion controls, and explaining, ''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).'').

In other actions the EPA has taken to implement good neighbor obligations, the EPA has required or allowed for reliance on source-specific emissions limitations rather than defining significant contribution as a mass-based budget. For example, the EPA imposed unit-specific emissions limitations in granting a CAA section 126(b) petition from the State of New Jersey in 2011. Final Response to Petition From New Jersey Regarding SO_2 Emissions From the Portland Generating Station, 76 FR 69052, 69063–64 (Nov. 7, 2011) (discussing the analytical basis for the establishment of emissions limits at specific units). This action was upheld by the Third Circuit in *Genon Rema LLC* v. *EPA,* 722 F.3d 513, 526 (3d. Cir. 2013).[83]

[80] The Agency's view of the basis for backstop daily emissions rates for certain EGUs within the trading program has changed since the time of its action on Delaware's petition, as explained in section VI.B.

[81] The EPA has interpreted the term ''amount'' as used in CAA section 111(a)(4) in the definition of the term ''modifications'' as an increase in a rate of emissions expressed as kilograms per hour. 40 CFR 60.14(b).

[82] Notably, both the provisions of CAA section 171 and section 163 given as examples here were added by the CAA Amendments of 1977, in the same set of amendments that Congress first strengthened the good neighbor provision and added the term ''amounts.'' *See* Public Law 95–95, 91 Stat. 685, 693, 732, 746.

[83] In CAA section 126(c), Congress provided for the EPA to directly impose ''emission limitations'' to eliminate prohibited significant contribution. Notably, the statute affords the EPA and states flexibility in how an ''emissions limitation'' may be expressed, including as a ''quantity, rate, or concentration,'' *see* CAA section 302(k). It would make little sense that the EPA could only establish a mass-based definition of ''amounts'' under CAA section 110(a)(2)(D)(i)(I), when the statute provides for rate- or concentration-based limitations in CAA section 126, which directly incorporates

Even where the EPA has provided for implementation of good neighbor requirements through mass-based budgets, it has recognized that other approaches may be acceptable as providing an equivalent degree of emissions reduction to eliminate significant contribution. *See, e.g.,* NO_X SIP Call, 63 FR 57378–79 (discussing approvability of rate-based emissions limit approaches for implementing NO_X SIP Call and providing, ''the 2007 overall budget is an important accounting tool. However, the State is not required to demonstrate that it has limited its total NO_X emissions to the budget amounts. Thus, the overall budget amount is not an independently enforceable requirement.''); CAIR, 70 FR 25261–62 (discussing ways states could implement CAIR obligations, including through emission-rate limitations, so long as adequately demonstrated to achieve comparable reductions to CAIR's emissions budgets).

Finally, as it has in its prior transport FIP actions, the EPA has in this action provided guidance for states on methods by which they could replace this FIP with SIPs, and in so doing, continues to recognize substantial state flexibility in achieving an equivalent degree of emissions reduction that would successfully eliminate significant contribution for the 2015 ozone NAAQS. *See* section VI.D of this document. While the EPA has exercised the responsibility it has under CAA section 110(c)(1) to step into the shoes of the covered states and directly implement good neighbor requirements through a particular set of regulatory mechanisms in this action, we anticipate that states may identify alternative, equivalent mechanisms that we would be bound to evaluate and approve if satisfactory, should states seek to replace this FIP with a SIP.

For these reasons, the EPA disagrees with the contention that it is constrained by the good neighbor provision to define upwind state obligations solely by reference to a fixed, mass budget. We find it reasonable in this action to again determine the amount of ''significant contribution'' at Step 3 by reference to uniform levels of cost-effective emissions controls that can be applied across the upwind sources. And, we find it appropriate to implement those emissions reductions at Step 4 through mechanisms that go beyond fixed, mass-based, ozone-season long budgets.

The EPA's authority for its industrial source control strategies is further discussed in sections II.C. and III.B.1.c of this document. The relationship of the control strategy to the assessment of overcontrol is discussed in section V.D.4 of this document. The relationship of our FIP authority to state authorities and SIP calls under CAA section 110(k)(5) is further discussed in *RTC* sections 1 and 2.

a. Step 1 Approach

As proposed, the EPA applies the same basic method of the CSAPR Update and the Revised CSAPR Update for identifying nonattainment and maintenance receptors. However, we received comments arguing that the outcome of applying our methodology to identify receptors in 2023 appears overly optimistic in light of current measured data from the network of ambient air quality monitors across the country. These commenters suggest that the EPA give greater weight to current measured data as part of the method for identifying projected receptors. As discussed further in section IV.D of this document, the EPA has modified its approach for identifying receptors for this final rule in response to these comments.

This concern is more evident given that the 2023 ozone season is just a few months away, and the most recent measured ozone values in many areas strongly suggest that these areas will not likely see the substantial reduction in ozone levels that the 2016v2 and 2016v3 modeling continue to project.

It would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites. We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Despite the implications of the current measured data suggesting there will be a nonattainment problem at these sites in 2023, we cannot definitively establish that such sites will be in nonattainment in 2023 in light of our modeling projections. In the face of this uncertainty, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if our transport modeling projects that an area may reach attainment in 2023, we have other information indicating that there is an identified risk that attainment will not in fact be achieved in 2023. The EPA's analysis of these additional receptors further is explained in section IV.D of this document.

However, because we did not identify this basis for receptor-identification at proposal, in this final action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring promulgating a final FIP (and we have also deferred taking final action on that state's SIP submittal). This is the case for the State of Tennessee. Among the states that previously had their transport SIPs fully approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good neighbor obligations as expeditiously as practicable in a future action.

b. Step 2 Approach

The EPA applies the same approach for identifying which states are contributing to downwind nonattainment and maintenance receptors as it has applied in the three prior CSAPR rulemakings. CSAPR, the CSAPR Update, and the Revised CSAPR Update used a screening threshold of 1 percent of the NAAQS to identify upwind states that were ''linked'' to downwind air pollution problems. States with contributions greater than or equal to the threshold for at least one downwind nonattainment or maintenance receptor identified in Step 1 were identified in these rules as needing further evaluation of their good neighbor obligations to downwind states at Step 3.[84] The EPA evaluated each state's contribution based on the average relative downwind impact calculated

110(a)(2)(D)(i)(I). (In observing this, we do not concede that an ''emissions limitation'' itself could not also be expressed through a mass-based approach, which may be read as authorized by the term ''quantity,'' a term also used in CAA section 302(k).)

[84] For ozone, the impacts include those from VOC and NO_X from all sectors.

over multiple days.[85] States whose air quality impacts to all downwind receptors were below this threshold did not require further evaluation for measures to address transport. In other words, the EPA determined that these states did not contribute to downwind air quality problems and therefore had no emissions reduction obligations under the good neighbor provision. The EPA applies a relatively low contribution screening threshold because many downwind ozone nonattainment and maintenance receptors receive transport contributions from multiple upwind states. While the proportion of contribution from a single upwind state may be relatively small, the effect of collective contribution resulting from multiple upwind states may substantially contribute to nonattainment of or interference with maintenance of the NAAQS in downwind areas. The preambles to the proposed and final CSAPR rules discuss the use of the 1 percent threshold for CSAPR. *See* 75 FR 45237 (August 2, 2010); 76 FR 48238 (August 8, 2011). The same metric is discussed in the CSAPR Update, *see* 81 FR 74538, and in the Revised CSAPR Update, *see* 86 FR 23054. In this final rule, the EPA has updated the air quality modeling data used for determining contributions at Step 2 of the 4-step interstate transport framework using the 2016v3 modeling platform. The EPA continues to find that this threshold is appropriate to apply for the 2015 ozone NAAQS. This rule's application of the Step 2 approach is comprehensively described in section IV of this document.

Many commenters challenged the use of a 1 percent of NAAQS threshold or otherwise raised issues with the EPA's Step 2 methodology. These comments are addressed in section IV.F of this document and in the *RTC* document.

c. Step 3 Approach

The EPA continues to apply the same approach as the prior three CSAPR rulemakings for evaluating ''significant contribution'' at Step 3.[86] For states that are linked at Step 2 to downwind air quality problems, CSAPR, the CSAPR Update, and the Revised CSAPR Update evaluated NO_X reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds) in the multi-factor test. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA selected the technology breakpoint (represented by a cost threshold) that, in general, maximized cost-effectiveness—*i.e.,* that achieved a reasonable balance of incremental NO_X reduction potential and corresponding downwind ozone air quality improvements, relative to the other emissions budget levels evaluated. *See, e.g.,* 81 FR 74550. The EPA determined the level of emissions reductions associated with that level of control stringency to constitute significant contribution to nonattainment or interfere with maintenance of a NAAQS downwind. *See, e.g.,* 86 FR 23116. This approach was upheld by the U.S. Supreme Court in *EPA* v. *EME Homer City*.[87]

In this action, the EPA applies this approach to identify EGU and non-EGU NO_X control stringencies necessary to address significant contribution for the 2015 ozone NAAQS. The EPA applies a multifactor assessment using cost-thresholds, total emissions reduction potential, and downwind air quality effects as key factors in determining a reasonable balance of NO_X controls in light of the downwind air quality problems. The EPA's evaluation of available NO_X mitigation strategies for EGUs focuses on the same core set of measures as prior transport rules, and the EPA finalizes a control stringency for EGUs from these measures that is commensurate with the nature of the ongoing ozone nonattainment and maintenance problems observed for the 2015 ozone NAAQS. Similarly, in this action, the EPA includes other industrial sources (non-EGUs) in its Step 3 analysis and finalizes emissions limitations for certain non-EGU sources as needed to eliminate significant contribution and interference with maintenance. The available reductions and cost-levels for the non-EGU stringency is commensurate with the control strategy for EGUs.

In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA focused its Step 3 analysis on EGUs. In the Revised CSAPR Update, in response to the *Wisconsin* decision's finding that the EPA had not adequately evaluated potential non-EGU reductions, *see* 938 F.3d at 318, the EPA determined that the available NO_X emissions reductions from non-EGU sources, for purposes of addressing good neighbor obligations for the 2008 ozone NAAQS, at a comparable cost threshold to the required EGU emissions reductions (for which the EPA used an adjusted representative cost of $1,800 per ton), and based on the timing of when such measures could be implemented, did not provide a sufficiently meaningful and timely air quality improvement at the downwind receptors before those receptors were projected to resolve. *See* 86 FR 23110. On that basis, the EPA made a finding that emissions reductions from non-EGU sources were not required to eliminate significant contribution to downwind air quality problems under the interstate transport provision for the 2008 ozone NAAQS. In this rule, the EPA's ''significant contribution'' analysis at Step 3 of the 4-step framework includes a comprehensive evaluation of major stationary source non-EGU industries in the linked upwind states. The EPA finds that emissions from certain non-EGU sources in the upwind states significantly contribute to downwind air quality problems for the 2015 ozone NAAQS, and that cost-effective emissions reductions from these sources are required to eliminate significant contribution under the interstate transport provision. Therefore, this rule requires emissions reductions from non-EGU sources in upwind states to fulfill interstate transport obligations for the 2015 ozone NAAQS. This analysis is described fully in section V of this document.

In this rule, the EPA also continues to apply its approach for assessing and avoiding ''over-control.'' In *EME Homer*

[85] The number of days used in calculating the average contribution metric has historically been determined in a manner that is generally consistent with the EPA's recommendations for projecting future year ozone design values. Our ozone attainment demonstration modeling guidance at the time of CSAPR recommended using all model-predicted days above the NAAQS to calculate future year design values (*https://www3.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf*). In 2014, the EPA issued draft revised guidance that changed the recommended number of days to the top-10 model predicted days (*https://www3.epa.gov/ttn/scram/guidance/guide/Draft-O3-PM-RH-Modeling_Guidance-2014.pdf*). For the CSAPR Update, the EPA transitioned to calculating design values based on this draft revised approach. The revised modeling guidance was finalized in 2019 and, in this regard, the EPA is calculating both the ozone design values and the contributions based on a top-10 day approach (*https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf*).

[86] For simplicity, the EPA (and courts) at times will refer to the Step 3 analysis as determining ''significant contribution''; however, the EPA's approach at Step 3 also implements the ''interference with maintenance'' prong of the good neighbor provision by also addressing emissions that impact the maintenance receptors identified at Step 1. *See* 86 FR 23074 (''In effect, EPA's determination of what level of upwind contribution constitutes 'interference' with a maintenance receptor is the same determination as what constitutes 'significant contribution' for a nonattainment receptor. Nonetheless, this continues to give independent effect to prong 2 because the EPA applies a broader definition for identifying maintenance receptors, which accounts for the possibility of problems maintaining the NAAQS under realistic potential future conditions.''). *See also EME Homer City,* 795 F.3d 118, 136 (upholding this approach to prong 2).

[87] *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014).

City, the Supreme Court held that ''EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set.'' 572 U.S. at 521. The Court acknowledged that ''instances of 'over-control' in particular downwind locations may be incidental to reductions necessary to ensure attainment elsewhere.'' *Id.* at 492.

> Because individual upwind States often 'contribute significantly' to nonattainment in multiple downwind locations, the emissions reductions required to bring one linked downwind State into attainment may well be large enough to push other linked downwind States over the attainment line. As the Good Neighbor Provision seeks attainment in *every* downwind State, however, exceeding attainment in one State cannot rank as 'over-control' unless unnecessary to achieving attainment in *any* downwind State. Only reductions unnecessary to downwind attainment *anywhere* fall outside the Agency's statutory authority.

Id. at 522 (footnotes omitted).

The Court further explained that ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' *Id.* at 523. Therefore, in the CSAPR Update and Revised CSAPR Update, the EPA evaluated possible over-control by considering whether an upwind state is linked solely to downwind air quality problems that can be resolved at a lower cost threshold, or if upwind states would reduce their emissions at a lower cost threshold to the extent that they would no longer meet or exceed the 1 percent air quality contribution threshold. *See, e.g.,* 81 FR 74551–52. *See also Wisconsin,* 938 F.3d at 325 (over-control must be proven through a '' 'particularized, as-applied challenge' '') (quoting *EME Homer City Generation,* 572 U.S. at 523–24). The EPA continues to apply this framework for assessing over-control in this rule, and, as discussed in section V.D.4 of this document, does not find any over-control at the final control stringency selected.

This evaluation of cost, NO_X reductions, and air quality improvements, including consideration of whether there is proven over-control, results in the EPA's determination of the appropriate level of upwind control stringency that would result in elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas.

Comment: Commenters alleged that the EPA lacks authority to regulate EGUs under the good neighbor provision of the CAA, or at least in the manner proposed, because in their view, this regulation would intrude into areas of regulation that are reserved to other Federal agencies or are beyond the EPA's expertise. They focused in particular on the EGU trading program enhancements, which they alleged would threaten electric grid reliability, and asserted that EPA lacks authority or expertise to dictate the mix of electricity generation in the country.

Response: The EPA disagrees that the regulation of EGUs in this action is unlawful or unsupported. The Agency has consistently and successfully regulated EGUs' ozone season NO_X emissions under the good neighbor provision for over 25 years, beginning with the 1997 NO_X SIP Call. This action does not intrude on other Federal agencies' authorities and responsibilities with respect to managing the electric power grid and ensuring reliable electricity. While other agencies such as the Federal Energy Regulatory Commission (FERC) have primary responsibility for ensuring reliability of the bulk electric system, the EPA has ensured that its final rule here will not create electric reliability concerns. See section VI.B.1.d of this document. Thus, to the extent commenters are raising a record-based issue that the EPA through this action has created a reliability concern, we disagree. The EPA engaged in a series of stakeholder meetings with Reliability Coordinators who commented on the proposed rule, including several Regional Transmission Organizations (RTOs) as well as non-RTO entities throughout the rulemaking process.[88]

To the extent commenters maintain that—despite this record of collaboration and sensitivity to the need to ensure reliability in the implementation of its mandates, including in this rule—the EPA nonetheless fundamentally lacks authority to regulate the electric-power sector in any way that ''impact[s] national electricity and energy markets,'' the EPA disagrees. The EPA has successfully regulated interstate ozone-precursor emissions from the power sector since the NO_X SIP Call and the establishment of the NO_X Budget Trading Program. *See generally Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000); *Appalachian Power Co.* v. *EPA,* 249 F.3d 1032 (D.C. Cir. 2001). In fact, each of the EPA's interstate ozone transport rulemakings has focused on the regulation of ozone-precursor emissions from the power sector (all but the NO_X SIP Call exclusively), because substantial, cost-effective reductions in ozone-precursor emissions have been and continue to be available from fossil-fuel fired EGUs. *See, e.g.,* 63 FR 57399–400 (NO_X SIP Call); 70 FR 25165 and 71 FR 25343 (CAIR and CAIR FIP); 76 FR 48210–11 (CSAPR); 81 FR 74507 (CSAPR Update); 86 FR 23061 (Revised CSAPR Update).[89]

This rule, like all prior EPA ozone-transport rulemakings, regulates only one aspect of the operation of fossil-fuel fired EGUs, that is, the emissions of NO_X as an ozone-precursor pollutant during the ozone season. This rule limits EGU NO_X emissions that interfere with downwind states' ability to attain and maintain the 2015 ozone NAAQS. The rule does not regulate any other aspect of energy generation, distribution, or sale. For these reasons, the rule does not intrude on FERC's power under the Federal Power Act, 16 U.S.C. 791a, *et seq.* And, as in prior transport rules, the EPA implements this regulation through a proven, flexible mass-based emissions trading program that integrates well with, and in no way intrudes upon, the management of the power sector under other state and Federal authorities. This rule will not alter the procedures system operators employ to dispatch resources or force changes to FERC-jurisdictional electricity markets, nor have commenters offered any explanation in this regard themselves.

The actual compliance requirement that the EGUs must meet in the allowance trading system finalized here—just as in all prior interstate transport trading programs—is simply to hold sufficient allowances to cover emissions during a given control period, not to undertake any specific

[88] See Documents no. EPA–HQ–OAR–2021–0668–0938, EPA–HQ–OAR–2021–0668–0940, EPA–HQ–OAR–2021–0668–0941, EPA–HQ–OAR–2021–0668–0942, EPA–HQ–OAR–2021–0668–0943, EPA–HQ–OAR–2021–0668–0944, and EPA–HQ–OAR–2021–0668–0945 in the docket for this rulemaking.

[89] There are myriad other examples of effective power sector regulation under the CAA and other environmental statutes, including for example, new source performance standards (NSPS), best available retrofit technology (BART) requirements, and mercury and air toxics standards (MATS) under the CAA; effluent limitation guidelines (ELGs) under the Clean Water Act; and coal combustion residuals (CCR) requirements under the Resource Conservation and Recovery Act. Whether implemented through unit- or facility-level pollution control requirements or through emissions-trading or other market-based programs, these regulations have been effective in reducing air and water pollution while not intruding into the regulatory arenas of other state and Federal entities. *See* Section 1 of the *RTC* for further discussion.

compliance strategy.[90] The owner or operator of an EGU has flexibility in determining how it will meet this requirement, whether through the add-on emissions controls that the EPA has selected in our Step 3 analysis, or through some other method or methods of compliance. The costs of meeting this allowance-holding requirement—just like the cost associated with meeting any other regulatory requirements—could possibly then be factored into what that unit bids in the wholesale electricity market (or in regulated jurisdictions, would factor into utility regulators' determinations of what can be cost-recovered).

Those costs could, in turn, result in a reduction in electricity generation from higher-emitting sources and an increase in electricity generation from lower-emitting or zero-emitting generators, but that kind of generation shifting (not mandated but occurring as an economic choice by the regulated sources) is consistent, and in no way interferes with, the existing security-constrained economic dispatch protocols of the modern electrical grid. Further, this type of ''impact'' on electricity markets—merely incidental, not mandated or even intended—is of the same type that results from any other kind of regulation, environmental or otherwise. Indeed, the U.S. Supreme Court recognizes that regulatory actions that may have some ''effect,'' or impact, in electricity markets do not on that basis alone intrude into authorities reserved to electricity rate-setting regulators by the Federal Power Act. *See FERC* v. *Electric Power Supply Ass'n,* 577 U.S. 260, 282–84 (2016) (distinguishing between actions that have an effect on retail rates and actual intrusion into retail rate-setting itself); *see also Hughes* v. *Talen,* 578 U.S. 150, 166 (2016). The Supreme Court again recognized this distinction between ''incidental'' effects caused by lawfully issued environmental regulations and attempts to mandate a particular energy mix in *West Virginia* v. *EPA. See* 142 S. Ct. 2587, 2613 n.4 (2022) (''[T]here is an obvious difference between (1) issuing a rule that may end up causing an incidental loss of coal's market share, and (2) simply announcing what the market share of coal, natural gas, wind, and solar must be . . . .'').

This rule is squarely in the former camp; as the most stringent component of its emissions controls strategy for EGUs, the EPA has determined that to eliminate significant contribution to harmful levels of ozone in other states, certain fossil-fuel fired EGUs in ''linked'' upwind states that do not already have selective catalytic reduction (SCR) post-combustion control technology, should install it (or achieve emissions reductions commensurate with that technology). SCR is a well-established at-the-source NO_X control technology already in use by EGUs representing roughly 60 percent of the existing coal-fired generating capacity in the United States. This technology can be installed and operated to reduce NO_X emissions without forcing the retirement or reduced utilization of any EGU. However, if market conditions are such that an EGU faced with this mandate (again, as expressed through an emissions trading budget) finds it more economic to comply with the mandate through the purchase of allowances, installation of other types of pollution control, reduced utilization, and/or retirement, rather than installing SCR technology, that is a choice that the EGU owner/operator can freely make under this rule.[91] Security constrained economic dispatch is thereby maintained and is in no way interfered with.

The EPA recognizes that cost to operate generators is one of the major factors that system operators utilize to determine ''merit'' order in dispatching resources. However, this rule does not intrude in any way into that process. To the extent that compliance with environmental regulations is a kind of cost that may need to be factored into generators' bids, this rule is no different than many other such requirements EGUs are already subject to. Further, as in prior transport rules, this rule applies a uniform control stringency to EGUs within the covered upwind states. EGUs that may have enjoyed a competitive advantage in the past through not bearing the costs of installing and running state-of-the-art emissions control technology now must bear that cost just as their competitors with that technology already are. *Cf. EME Homer City,* 572 U.S. 489, 519 (CSAPR is ''[e]quitable because, by imposing uniform cost thresholds on regulated States, EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to bring down their emissions by installing devices of the kind in which neighboring States have already invested.'').

Finally, we note that this final rule does not include ''generation shifting'' as a component of the budget-setting process, even in the limited way that it had been used in prior transport rules like CSAPR and the CSAPR Update, *i.e.,* to ensure the budget provided adequate incentive to ensure implementation of the selected emission-control strategy. *See* section V.B.1.f of this document. Further comments regarding legal authority for ''generation shifting,'' relationship to state authorities, and expertise associated with grid reliability are addressed in section 1.3 of the *RTC.* We further discuss our consideration of grid reliability concerns and adjustments in the approach to the EGU emissions trading program from proposal in section VI.B.1.d of this document.

Comment: Commenters generally challenged the EPA's authority to establish emissions control requirements for non-EGU industrial sources in this action, or argued that such controls are unnecessary or unsupported, or run contrary to the EPA's prior actions under the good neighbor provision.

Response: The states and the EPA have authority under CAA section 110(a)(2)(D)(i)(I) to prohibit emissions from ''any source or other type of emissions activity'' that are found to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states. This language is not limited only to power plant emissions, nor is it limited only to ''major'' sources or ''stationary'' sources. Thus, as a legal

[90] The EPA has included in this trading program certain ''enhancements'' to ensure that the program continues to eliminate the emissions the EPA has determined constitute ''significant contribution'' over the entire life of the trading program. While one of the enhancements elevates a type of conduct that was already strongly discouraged into an enforceable violation, the other enhancements all simply modify the traditional allowance-based program structure to revise how the specific quantities of allowances that must be surrendered or the specific quantities of allowances available for surrender are determined. In finalizing this rule, the EPA has made a number of changes to its proposed enhancements to the trading program in response to comment and in part to ensure no impact on system reliability. Nonetheless, with these changes, the EPA has determined that the enhanced trading program can be implemented without impacting grid reliability. See section VI.B.1.d of this document.

[91] As explained in section V.B of this document, the imposition of a backstop emissions rate beginning in 2030 for units that do not already have SCR installed could lead the owner of a given unit to decide that the unit's continued operation would be uneconomic without installation of SCR, but the establishment of technology-based emissions rates that require such decisions is consistent with decades of the EPA's rulemaking and permitting actions requiring source-specific pollution controls. Further, the backstop rate in this program is implemented through an enhanced allowance-surrender ratio, thus preserving some degree of flexibility through the emissions-trading program as the mechanism of compliance.

matter, the emissions control requirements for certain large ''non-EGU'' industrial sources in this action are grounded in unambiguous statutory authority, in particular the statute's use of the broad term ''any source.'' Whereas the Act elsewhere includes definitions of ''major stationary source,'' ''small source,'' and ''stationary source,'' *see, e.g.,* CAA section 302(j), (x), and (z), no such qualifying terms are used with respect to the term ''any source'' at CAA section 110(a)(2)(D)(i). Rather, the scope of authority in this provision expands to encompass ''other type of emissions activity'' in addition to ''any source.'' The EPA has previously included non-EGU industrial sources in findings quantifying states' obligations under the good neighbor provision, in the 1998 NO_X SIP Call, *see* 63 FR 57365.[92] *See also Michigan* v. *EPA,* 213 F.3d 663, 690–93 (upholding the inclusion of certain non-EGU boilers in the NO_X SIP Call). The EPA's determinations in prior transport rules not to regulate sources beyond the power sector were grounded in considerations not related to the Agency's statutory authority. For example, in the original CSAPR rulemaking, the EPA determined that the analytical effort needed to regulate non-EGU industrial sources would substantially delay the implementation of emissions reductions from the power sector. *See, e.g.,* 76 FR 48247–48 (''[D]eveloping the additional information needed to consider NO_X emissions from non-EGU source categories to fully quantify upwind state responsibility with respect to the 1997 ozone NAAQS would substantially delay promulgation of the Transport Rule. . . . [W]e do not believe that effort should delay the emissions reductions and large health benefits this final rule will deliver[.]''). The EPA acknowledged that by not addressing non-EGUs, it may not have promulgated a complete remedy to good neighbor obligations in CSAPR, *id.* at 48248. Nonetheless, the EPA went on to explain that there were limited emissions reductions available from non-EGUs at the cost thresholds the EPA determined would deliver substantial reductions from power plants. *See id.* at 48249 (the EPA's ''preliminary assessment in the rule proposal suggested that there likely would be very large emissions reductions available from EGUs before costs reach the point for which non-EGU sources have available reductions . . . . EPA revisited these non-EGU reduction cost levels in this final rulemaking and verified that there are little or no reductions available from non-EGUs at costs lower than the thresholds that EPA has chosen . . . .''). The EPA noted in CSAPR that states retained the authority to regulate non-EGUs as a method of addressing their good neighbor obligations. *Id.* at 48320. The EPA also noted in CSAPR that ''potentially substantial'' non-EGU emissions reductions could be available in future rulemakings applying a higher cost threshold. *See id.* at 48256.

Similarly, in the CSAPR Update, which addressed good neighbor obligations for the 2008 ozone NAAQS, the EPA found that regulation of non-EGUs was not warranted as the analysis required could delay the expeditious implementation of power plant reductions. The EPA found that the availability and cost-effectiveness of non-EGU reductions was uncertain and further analysis could delay implementation of the EGU strategy beyond 2017. The EPA acknowledged that it was not promulgating a complete remedy for good neighbor obligations for the 2008 ozone NAAQS and indicated its intention to further review emissions-reduction opportunities from non-EGU and EGU sources. 81 FR 74521–22.

In *Wisconsin,* the court held that the EPA's deferral of a complete good neighbor remedy by 2017, on the basis, among other things, of uncertainty regarding non-EGU emissions reductions and the need for further regulatory analysis, was unlawful. 938 F.3d at 318–19. The court noted that '' 'the statutes and common sense demand regulatory action to prevent harm, even if the regulator is less than certain.' '' *Id.* at 319 (quoting *Ethyl Corp.* v. *EPA,* 541 F.2d 1, 24–25 (D.C. Cir. 1976)), and that agencies can only avoid meeting their statutory obligations where ''scientific uncertainty is so profound that it precludes EPA from making a reasoned judgment.'' *Id.* (citing *Massachusetts* v. *EPA,* 549 U.S. 497, 534 (2007)). Further, the court rejected the EPA's argument that it would have delayed its rulemaking if the EPA needed to complete a non-EGU analysis in a timely manner, holding that ''administrative infeasibility'' is not sufficient to ''justify . . . noncompliance with the statute.'' *Id.* Rather, the Agency would need to ''meet the 'heavy burden to demonstrate the existence of an impossibility.' '' *Id.* (quoting *Sierra Club* v. *EPA,* 719 F.2d 436, 462 (D.C. Cir. 1983)).

Following the remand of the CSAPR Update in *Wisconsin,* in the Revised CSAPR Update, the EPA conducted an analysis of non-EGUs to ensure it had implemented a complete remedy to eliminate significant contribution for the covered states for the 2008 ozone NAAQS. While acknowledging uncertainty in the datasets for non-EGUs, the EPA concluded: ''[U]sing the best information currently available to the Agency, . . . the EPA is concluding that there are relatively fewer emissions reductions available at a cost threshold comparable to the cost threshold selected for EGUs. In the EPA's reasoned judgment, the Agency concludes such reductions are estimated to have a much smaller effect on any downwind receptor in the year by which the EPA finds such controls could be installed.'' 86 FR 23059. Therefore, the EPA determined control of non-EGU emissions was not required to eliminate significant contribution for the 2008 ozone NAAQS.

The circumstances that led the EPA to defer or decline regulation of non-EGU sources in CSAPR, the CSAPR Update, and the Revised CSAPR Update, are not present here, and the EPA's determination in this action that prohibiting certain emissions from certain non-EGU sources is necessary to eliminate significant contribution for the 2015 ozone NAAQS is a logical extension of the analyses and evolution of regulatory policy development spanning its prior good neighbor rules, now applied to implement this more protective NAAQS. As the EPA explained at proposal, unlike in CSAPR and the Revised CSAPR Update, in this action the EPA finds that available reductions and cost-levels for the non-EGU stringency are commensurate with the control strategy for EGUs. Following consideration of comments and after some adjustments in the non-EGU analysis and control strategy, in this final rule, the EPA continues to find this to be the case. *See* sections V.C and V.D of this document.

In particular, the EPA continues to find that cost-effective emissions reductions are available for non-EGUs at a representative cost-threshold that is lower than the cost-threshold the EPA is applying for EGUs. *See* section V.C. of this document. These emissions control strategies are generally comparable to the emissions reduction requirements that similar sources in downwind states

[92] Specifically, in the NO_X SIP Call, the EPA set statewide budgets while states could determine which sectors to regulate. The EPA recommended that states regulate certain types of non-EGUs and quantified the statewide budgets based in part on the emissions reductions from those types of non-EGUs. In the parallel rule that followed under the EPA's CAA section 126(b) authority to directly regulate emissions to eliminate significant contribution, we promulgated an emissions trading program that would have included these same types of non-EGUs. Before this rule was implemented, all states adopted equivalent state trading programs using the NO_X SIP Call model rule.

are already required to meet. *See* section V.B.2 of this document. The EPA finds that the implementation of these emissions control strategies at non-EGUs, in conjunction with the strategies for EGU, will make a cost-effective and meaningful improvement in air quality through reducing ozone levels at the identified downwind receptors, and, therefore, the EPA has determined that these strategies will eliminate the amount of upwind emissions needed to address significant contribution under the good neighbor provision. The EPA's action here is focused on the most impactful industries and emissions units as determined by our evaluation of the power sector and the non-EGU screening assessment prepared for the proposal; indeed, of the 41 industries, as identified by North American Industry Classification System codes, we analyzed, only nine industries met the criteria for further evaluation of significant contribution. *See* section V.B.2 of this document. Further, the EPA finds that these strategies do not result in ''overcontrol.'' *See* section V.D.4 of this document. As such, the EPA maintains that its final determinations regarding non-EGUs and its inclusion of non-EGU emissions sources within this final rule are statutorily authorized and lawful.[93]

The EPA disagrees that it should defer regulation of industrial sources to the NSPS program under CAA section 111(b). CAA section 111(b) does not expressly provide for the elimination of ''significant contribution'' as is required under CAA section 110(a)(2)(D)(i)(I). In particular, commenter's statement that NSPS rulemakings under section 111(b) will appropriately address the emissions that we find must be eliminated in this action is not correct. Standards under section 111(b) apply only to new and modified sources, not existing sources. This action, however, finds that reductions in ongoing emissions from existing sources are needed to eliminate significant contribution. An NSPS standard for new and modified sources would not address such emissions from existing sources. To the extent that covered sources in this action also may be covered by an older NSPS, these sources nonetheless continue to have emissions that the EPA finds significantly contribute and can be eliminated through further emissions control as determined in this action. We further disagree with commenter's separate suggestion that the EPA use section 111(b) and (d) to regulate both new and existing sources of ozone season NO_X, which is premised on the incorrect notion that the EPA's action here is an attempt to regulate entire source categories nationwide, rather than to eliminate significant contribution pursuant to CAA section 110(a)(2)(D)(i)(I). This action applies only to the extent a state is ''linked'' to downwind receptors, and therefore this action only regulates covered non-EGU industrial sources in 20 states. Further, this comment ignores that the regulation of criteria pollutant emissions from existing sources under CAA section 111(d) is limited by the criteria pollutant exclusion in CAA section 111(d)(1)(A)(i).

The EPA agrees with the commenters who assert that the EPA's authority to regulate non-EGUs under the good neighbor provision is well-grounded in administrative precedent and case law. Our previous discussion briefly recites several of the most salient aspects of that history. We also agree that the statutory language is not limited only to those sources that emit above 100 tons per year. The EPA's Step 3 and Step 4 analyses in this regard, which establish certain thresholds based on historical actual emissions, potential to emit and/or metrics for unit design capacity, reflect a reasoned judgment by the Agency regarding which emissions can be cost-effectively eliminated to address significant contribution, under the facts and circumstances of this action. That these thresholds are designed to exclude certain smaller or lower-emitting units does not reflect a determination that the EPA lacks legal authority to regulate such sources under different facts and circumstances.

The EPA identified two industry tiers of potential non-EGU emissions reductions in its non-EGU screening assessment at proposal, based on screening metrics intended to capture different kinds of impacts that non-EGU sources may have on identified receptors. The EPA agrees that it is only authorized to prohibit emissions under the good neighbor provision that significantly contribute to nonattainment or interfere with maintenance in downwind states, and we determined that these industries did so. The EPA sought comment on whether additional non-EGU industries significantly contributed to nonattainment or interfered with maintenance in downwind states. The EPA did not receive comments identifying other industrial stationary sources that are more impactful that should be regulated instead of those the EPA identified. We believed at proposal and confirm here in our final rule that the methodology used in the screening assessment comported with the factors that we consider at Step 3. Further, the EPA's 4-step interstate transport framework, including the Step 3 analysis and an overcontrol assessment, ensure that the emissions reductions achieved at each source covered by this rule are in fact justified as part of an overall, complete remedy to eliminate significant contribution for the covered states for the 2015 ozone NAAQS. The EPA has decided to finalize emissions limitations for all of the non-EGU industries, with some modifications from proposal reflecting public input, as discussed in section VI.C of this document. The Agency's authority to establish unit- and/or source-specific emissions limitations in exercising our FIP authority is further discussed in section III.B.1 of this document.

Comment: Commenters raise additional issues with the overall approach of the rule at Step 3 to address significant contribution through our evaluation of EGU and non-EGU strategies through parallel but separate analyses. They stated that the EPA failed to establish that the identified non-EGU emissions reductions are needed to eliminate significant contribution. Commenters stated that the identified non-EGU emissions reductions are not impactful of air quality at receptors or that they are much less cost-effective than the EGU emissions reductions. Commenters stated that the EPA grouped all non-EGU emissions reductions together in making a cost-effectiveness determination that is only an average and ignores significant variation in costs associated with controls on different types of non-EGU emissions units. They also stated the EPA did not assess multiple control technologies in the way that it did for EGUs, and they argued there is great variation in the profile of non-EGU industries and emissions unit types in the different upwind states or that individual emissions units do not contribute to an out-of-state air quality problem at all. Commenters argued that certain non-EGU controls were not feasible, or that the EPA had applied a different standard for ''feasibility'' for non-EGUs than it did for EGUs. Commenters stated that the EPA should have provided a mass-based trading option for non-EGUs just as it had for EGUs. By contrast, other commenters supported the regulation of non-EGUs in this action as necessary to ensure a complete remedy to good neighbor obligations, since the statute is not limited to regulating power plants.

[93] Certain changes in the emissions control strategies for non-EGUs reflecting comments and updated information are explained in section VI.C of this document.

Some commenters further stated that EGUs should not face any further emissions reduction obligation because all cost-effective controls have already been identified through prior transport rules, and that any further regulation of EGUs would only lead to the retirement of coal plants, which they believe is the EPA's true objective. Finally, some commenters argued that the EPA had not ensured that it only regulated up to the minimum needed for downwind areas to come into attainment.

Response: Issues related to the specific technical bases for the Agency's determinations of what emissions constitute ''significant contribution'' at Step 3 of the 4-step framework are addressed in section V of this document. Here, we evaluate commenters' more general assertions that this action addresses non-EGU or EGU emissions in an inconsistent way. First, the EPA agrees with commenters that the task of evaluating significant contribution from the non-EGU industries is complex compared to EGUs in light of the much greater diversity in industries and emissions unit types. This, however, is not a valid basis to avoid emissions control requirements on such sources if needed to eliminate significant contribution. In this respect, the EPA's analysis in this final rule is that the 4-step framework, as upheld by the Supreme Court in *EME Homer City,* can be adequately applied even to this more complex set of sources in a way that parallels the analysis previously conducted only for EGUs. This analysis relies on evaluation of uniform levels of control stringency across all upwind states to find a level of emissions control that is cost-effective and collectively delivers meaningful downwind air quality improvement. For non-EGUs, the EPA identified the most impactful industries and emissions unit types and evaluated emissions control strategies for these units that have been demonstrated or applied across many similar facilities and emissions units. The EPA has evaluated whether these strategies are cost-effective on a cost-per-ton basis, and in particular has compared these strategies to those selected for EGUs. This analysis is set forth in sections V and VI of this document and associated technical support documents.

Commenter's statement that the establishment of a uniform level of control for each group of industrial units across the linked upwind states fails to assess with greater precision or define a state-specific proportion of emissions reduction that is needed for each downwind receptor is effectively an attempt to relitigate *EME Homer City.* The Court in that case rejected that the EPA must define significant contribution by reference to a specific quantum of reductions that each state must achieve that is proportional to its impact at a downwind receptor. The Court agreed with the EPA's concerns as to why that approach would be problematically complicated or even impossible to apply in light of the complex set of linkages among states for a regional pollutant like ozone. *See* 572 U.S. at 515–17. The Court found that the use of uniform cost thresholds to allocate responsibility for good neighbor obligations to be efficient and equitable, in that it requires those sources that have done less to reduce their emissions to come up to a minimum level of performance to what other sources are already achieving. *Id.* at 519. The EPA's analysis in this action in section V of this document establishes that this continues to be an appropriate means of delivering meaningful air quality improvement to downwind receptors, taking into consideration the complexities of interstate pollution transport.

Not every upwind state has the same mix of non-EGU industries and emissions unit types, and it is also the case that the costs for installation of the selected level of control technology will vary from facility to facility based on site-specific considerations. This is also true for the set of EGU sources regulated here and in previous CSAPR rulemakings. These real-world complexities do not obviate the broader policy and technical judgements that the EPA makes at Step 3 regarding what level of emissions control performance can be achieved on a region-wide basis to resolve significant contribution for a regional-scale pollutant like ozone. The EPA's design of cost thresholds derives from the identification of discrete types of NO_X emissions control strategies. The EPA then identifies a representative cost-effectiveness on a per ton basis for that technology. In the Step 3 analysis, it is not the cost per ton value itself that is inherently meaningful, but rather how that cost-effectiveness value relates to other control stringencies, how many emissions reductions may be obtained, and how air quality is ultimately impacted. The selected level of control stringency reflects a point at which further emissions mitigation strategies become excessively costly on a per-ton basis while also delivering far fewer additional emissions reductions and air quality benefits. This is often referred to as a ''knee in the curve'' analysis. There are always inherent uncertainties in identifying a representative cost per ton value for any particular control stringency, but this in itself does not upset the EPA's ability to render an overall policy judgment based on the Step 3 factors as to a set of emissions control strategies that together eliminate significant contribution. *See* 86 FR 23054, 23073 (responding to similar comments on the Revised CSAPR Update).

We note that the EPA has made a number of adjustments to the non-EGU emissions limits identified at Step 4 to accommodate legitimate concerns regarding the ability of certain non-EGU facilities to meet the emissions control requirements that the EPA had proposed. The Agency's determinations regarding feasibility and installation timing for pollution controls are comparable and not inconsistent between EGUs and non-EGUs. The EPA is not establishing a trading program for non-EGUs because the Agency does not have adequate baseline emissions data and information on monitoring currently at many of these emissions units to develop emissions budgets that could reliably implement the Step 3 determinations made in this action. However, for most of the non-EGU industries,[94] the EPA is not mandating a specific control technology and is instead establishing numeric emissions limits that are uniform across the region and that allow sources to choose how to comply. The EPA's analysis, including review of RACT determinations, consent decrees, and permitting actions, shows that these emissions limits and control requirements are achievable by existing units in the non-EGU industries covered by this final rule. This rule will therefore bring all of these impactful industries and unit types across the region of linked upwind states up to this standard of performance, and thus will result collectively in a relatively substantial decrease in ozone-season NO_X emissions, with associated reductions in ozone levels projected to result at the downwind receptors. This is further discussed in section V.D.

Some commenters alleged that the EPA's EGU control strategy goes beyond the cost-effectiveness determinations of prior transport rules, and they believe that the EPA's true objective is to force the retirement of coal plants. First, we note that the EGU emissions control strategy is premised entirely on at-the-

[94] For reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing industry, the EPA is establishing requirements to operate low-NO_X burners achieving a specified level of emissions reduction; this approach is needed to allow for unit-specific testing before an appropriate emissions limitation can be set. *See* section VI.C.3 of this document.

source emissions control technologies that are widely available and in use across the EGU fleet. It is not the EPA's intention in this rule to force the retirement of any EGU or non-EGU facilities or emissions units but to identify and eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I) based on cost-effective and proven control technologies that are appropriate in relation to address the problem of interstate transport for the 2015 ozone NAAQS. Further, determinations of cost-effectiveness must be made in relation to the particular statutory provision and its purpose. The EPA recognized in CSAPR, for example, that additional emissions reductions beyond what were determined to be cost-effective in that action could be required to implement good neighbor obligations if a NAAQS were revised to a more protective level. *See* 76 FR 48210. Here it is not surprising that a more stringent level of control could be found justified in implementing transport obligations for the more protective 2015 ozone NAAQS. Those reductions are projected to deliver meaningful air quality improvement to downwind receptors, as discussed in section V.D of this document. Those air quality benefits continue to compare favorably to the air quality benefits that will be delivered through the combined non-EGU emissions limits, which apply to nine non-EGU industries (see section V.C of this document). We find that the implementation of both the EGU and non-EGU strategies identified in section V of this document together represent the appropriate level of emissions control stringency to eliminate significant contribution under CAA section 110(a)(2)(D)(i)(I).

Finally, the EPA also analyzed for overcontrol and does not identify any. Some commenters misstate the purpose of this rule as bringing downwind receptors into attainment. In line with the statutory directive in CAA section 110(a)(2)(D)(i)(I), this rule eliminates ''significant contribution'' from upwind states; while the rule has substantial air quality benefits for downwind receptors, in many cases we project that a nonattainment or maintenance problem will continue to persist through 2023 and 2026 despite the emissions reductions achieved by this rule. Commenters alleging overcontrol have not met the requirement that overcontrol be established by particularized evidence through as-applied challenges. The Supreme Court has recognized that the EPA also has an obligation to avoid under-control and must have some leeway in fulfilling the good neighbor mandate of the Act given uncertainty in making forward projections of air quality and the efficacy or impact of emissions control determinations. *See EME Homer City,* 572 U.S. at 523. This is further addressed in section V.D.4 of this document.

d. Step 4 Approach

The EPA is finalizing an approach similar to its prior transport rulemakings to implement the necessary emissions reductions through permanent and enforceable measures. The EPA is requiring EGU sources to participate in an emissions trading program and is making additional enhancements to the trading regime to maintain the selected control stringency over time and improve emissions performance at individual units, offering a necessary measure of assurance that emissions controls will be operated throughout the ozone season. For non-EGUs, the EPA is finalizing permanent and enforceable emissions rate limits and work practice standards, and associated compliance requirements, for several types of NO_X-emitting combustion units across several industrial sectors. The measures for both EGUs and non-EGUs are required throughout the May 1-September 30 ozone season of each year. The EGU program will begin with the 2023 ozone season, and the non-EGU implementation schedule is targeted to the 2026 ozone season. Refer to section VI.A of this document for details on the implementation schedule.

Based on the EPA's experience in implementing prior transport rulemakings, the Agency is making several enhancements to its trading-program approach for implementing good neighbor requirements for EGUs. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA established interstate trading programs for EGUs to implement the necessary emissions reductions. In each of these rules, EGUs in each covered state are assigned an emissions budget in each control period for their collective emissions. Emissions allowances are allocated to units covered by the trading program, and the covered units then surrender allowances after the close of the control period, usually in an amount equal to their ozone season EGU NO_X emissions. While these programs have been effective in achieving overall reductions in emissions, experience has shown that these programs may not fully reflect in perpetuity the degree of emissions stringency determined necessary to eliminate significant contribution in Step 3 and may not adequately ensure the control of emissions throughout all days of the ozone season. At the same time, the EPA continues to find that an interstate-trading program approach delivers substantial benefits at Step 4 in terms of affording an appropriate degree of compliance flexibility, certainty in emissions outcomes, data and performance transparency, and cost-effective achievement of a high degree of aggregate emissions reductions. As such, the EPA is retaining an interstate trading program approach while making several enhancements to that approach.

Thus, in this rulemaking, the EPA is including dynamic budget-setting procedures in the regulations that will allow state emissions budgets for control periods in 2026 and later years to reflect more current data on the composition and utilization of the EGU fleet (*e.g.,* the 2026 budgets will reflect recent data through 2024 data, the 2027 budgets will reflect data through 2025, etc.). These enhancements will enable the trading program to better maintain over time the selected control stringency that was determined to be necessary to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. In prior programs, where state emissions budgets were static across years rather than calibrated to yearly fleet changes, the EPA has observed instances of units idling their emissions controls in the latter years of the program. To provide greater certainty regarding the minimum quantities of allowances that will be available for compliance for the control periods in 2026 through 2029, the EPA is also establishing preset state emissions budgets for these control periods, and a dynamic state emissions budget determined for one of these control periods will apply only if it is higher than the state's preset budget for the control period.

In the trading programs established for ozone season NO_X emissions under CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA included assurance provisions to limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders in the instance that emissions in the state exceed this level. This limit on the degree to which a state's emissions can exceed its budget is designed to allow for a certain level of year-to-year variability in power sector emissions to account for fluctuations in demand and EGU operations and is responsive to previous court decisions (see discussion in section VI.B.5 of this document). In this action, the EPA is maintaining the existing assurance provisions that limit state emissions to levels below a percentage of the state's budget by requiring additional allowance surrenders in any instance where emissions in the state exceed the specified level, but with adjustments that allow the level to exceed 121 percent of a state's budget in a given control period if necessary to account for actual operational conditions in that control period. In addition, the EPA is also making several additional enhancements to the EGU trading program in this action, including routine recalibrations of the total amount of banked allowances, unit-specific backstop daily emissions rates for certain units, and unit-specific secondary emissions limitations for certain units that contribute to exceedances of the assurance levels, to ensure EGU emissions control operation and associated air quality improvements. Implementation of the EGU emissions reductions using a CSAPR NO_X trading program is further described in section VI.B of this document.

In this rule, the EPA is also establishing emissions limitations for the non-EGU industry sources listed in Table II.A–1. The EPA has the authority to require emissions limitations from stationary sources, as well as from other sources and emissions activities, under CAA section 110(a)(2)(D)(i)(I). The EPA finds that requiring NO_X emissions reductions through emissions rate limits and control technology requirements for certain non-EGU industrial sources that the EPA found at Step 3 to be relatively impactful[95] on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA is establishing NO_X emissions limitations and associated compliance requirements for non-EGU sources to ensure the elimination of significant contribution of ozone precursor emissions required under the interstate transport provision for the 2015 ozone NAAQS.

Finally, the EPA finds that the control measures determined to be required for the identified EGU and non-EGU sources apply to both existing units and any new, modified, or reconstructed units meeting the applicability criteria established in this final rule. This is consistent with the EPA's transport actions dating back to the NO_X SIP Call and the NO_X Budget Trading Program. In all CSAPR EGU trading programs, for instance, new EGUs are subject to the program, and the EPA has established provisions for the allocation of allowances to such units through ''new unit set asides.'' *See, e.g.,* 86 FR 23126. In the NO_X SIP Call, the EPA required that states cover new and existing units in the relevant source sectors through an enforceable cap or other emissions limitation. *See* 40 CFR 51.121(f). The EPA's approach of including new units in the NO_X Budget Trading Program promulgated under the EPA's CAA section 126 authority was upheld by the D.C. Circuit in *Appalachian Power* v. *EPA,* 249 F.3d 1032 (2001). As the court noted, the EPA explained in its action:

> Once EPA has determined that the emissions from the existing sources in an upwind State already make a significant contribution to one or more petitioning downwind States, any additional emissions from a new source in that upwind State would also constitute a portion of that significant contribution, unless the emissions from that new source are limited to the level of highly effective controls.

Id. at 1058 (quoting EPA 1999 RTC at 39). The court affirmed this approach: ''Indeed, it would be irrational to enable the EPA to make findings that a group of sources in an upwind state contribute to downwind nonattainment, but then preclude the EPA from regulating new sources that contribute to that same pollution.'' *Id.* at 1057–58. The EPA is implementing the same court-affirmed approach in this action because this reasoning is equally applicable to addressing interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

Comment: Commenters took issue with aspects of the EPA's proposed Step 4 approach. Commenters argued the EPA could not set unit- or source-specific emissions limits or other control requirements, for EGUs or non-EGUs. Commenters argued that various aspects of the non-EGU emissions control strategy would not be feasible for their facilities or were otherwise flawed. Many industrial-source and EGU commenters argued that the EPA had not provided sufficient time for sources to come into compliance. Commenters also challenged the EGU trading program ''enhancements'' as unnecessary or beyond the EPA's authority. In this regard, commenters argued that these changes deviated from the EPA's prior approach, were unnecessary overcontrol, constituted a command-and-control approach, could not be supported on the basis of environmental justice benefits, or were otherwise unlawful for other reasons. These commenters argue that the EPA's Step 4 dynamic budget approach for EGU regulation purportedly re-defines each state's ''significant contribution'' annually and independent of any impact (or lack thereof) on air quality. They further argue that under this dynamic budgeting approach, even if a state eliminates the ''amount'' the EPA has identified as the state's significant contribution by respecting a given control period's emissions budget, sources within that state are expected to continue to make further reductions by operating their controls in a particular manner in subsequent control periods under potentially lower emissions budgets, which these commenters argue is inconsistent with case law on prior CSAPR rules.

Response: Many of these comments regarding Step 4 issues are addressed elsewhere in this document or in the *RTC* document. The EPA's authority to establish unit- or source-specific emissions rates is addressed in section IV.B.1 of this document. Responses to comments and adjustments in the timing requirements of the final rule compared to proposal are discussed in VI.A. Responses to comments and adjustments in emissions control requirements for non-EGUs in the final rule compared to proposal are in section VI.C of this document.

Responses to comments on the EGU trading program enhancements and adjustments in the final rule are contained in section VI.B of this document. However, here, in light of the changes in the emissions trading program for EGUs that we are finalizing in this action as compared to prior EGU emissions trading programs promulgated to address good neighbor obligations under other NAAQS, we set forth responses to comments specific to this topic.

The EPA finds that these comments confuse Step 3 emissions reduction stringency determinations with Step 4 implementation program details. In this rulemaking's Step 3 analysis, the EPA is measuring emissions reduction potential from improving effective emissions rates across groups of EGUs adopting applicable pollution control measures and selecting a uniform control level whose effective emissions rates deliver an acceptable outcome under the multifactor test (including a finding of no overcontrol at the selected control stringency level). The ''amounts'' defined as significant contribution to nonattainment and interference with maintenance are

[95] Section III of the Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes the EPA's approach to evaluating impacts on downwind air quality, considering estimated total, maximum, and average contributions from each industry and the total number of receptors with contributions from each industry.

emissions that occur at effective emissions rates above the control stringency level selected at Step 3. That is, if a state's affected EGUs fail to reduce their effective emissions rates in line with the widely available and cost-effective control measures identified, they have therefore failed to eliminate their significant contribution to nonattainment and interference with maintenance of this NAAQS.

In this rule, the EPA is finalizing several ''enhancements'' to its existing Group 3 emissions trading program for ozone season NO_X, for reasons explained in section VI.B.1 of this document. In general, these changes will ensure that the emissions control program promulgated for EGUs at Step 4 of the EPA's 4-step interstate transport framework is in alignment with the emissions control stringency determinations the EPA made at Step 3. These enhancements reflect lessons learned through the EPA's experience with prior trading programs implemented under the good neighbor provision and ensure that the implementation of the elimination of significant contribution through an emissions trading program remains durable through a period of power sector transition. None of commenters' arguments against the EPA's authority to implement these enhancements are persuasive.

First, the EPA is not mandating that any EGU must install SCR technology. All but one of the enhancements to the trading program continue to be implemented through allowance-holding requirements under the mass-based emissions budget and trading system, including the backstop rate. (The secondary emissions limitation, which is not implemented through allowance-holding requirements under the mass-based emissions budget and trading system, and which is discussed in section VI.B.1.c.ii of this document, merely establishes a stronger deterrent for a type of conduct that was already strongly discouraged under the pre-existing trading program regulations). Nonetheless, the EPA *does* have the authority to impose unit-specific emissions limits under the exercise of its FIP authority, and it has done so in this action for non-EGU industrial sources. This authority is distinct from the EPA's title I permitting authority as discussed by certain commenters, and the scope of that permitting authority is not relevant to this action.

The quantification of emissions budgets in an allowance-based emissions trading program is one of multiple potential Step 4 implementation program design choices that states and the EPA have authority to select in securing the emissions reductions deemed necessary under Step 3. *See* CAA section 110(a)(2)(A). The EPA and the states routinely determine control stringency on an emissions rate basis in line with demonstrated pollution control opportunities, and both the EPA and the states have implementation program design discretion to determine what compliance requirements, whether expressed on a rate, mass, concentration, or percentage basis, will assure an emissions performance that reflects the control stringency required. Dynamic budgets in the Step 4 implementation of this rule are simply to ensure the trading program continues to incentivize the implementation of the EGU control strategies we find are necessary to eliminate significant contribution at Step 3. The key distinction between dynamic budget approaches and preset budget approaches is not one in stringency or authority, but rather in timing and data resources for determining the suitable mass-based limits that are as well-matched as possible to expected emissions of the affected EGUs achieving the emissions rate-based control stringency deemed necessary under Step 3 to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS.

The EPA does not agree that the administrative mechanisms by which it will implement ''dynamic budgeting'' conflict with CAA section 307(d) or the Administrative Procedure Act. The EPA is promulgating a complete FIP in this action, and the codified language of that FIP will not need to be modified as budgets are adjusted. This is because the FIP establishes the formula by which the budgets will be calculated each year (with preset budgets functioning as a floor from 2026 through 2029). This is no different than how the EPA has implemented other calculations such as updating allocations using a rolling set of data in its prior CSAPR trading programs. *See, e.g.,* 87 FR 10786. We view these actions as fundamentally ministerial in nature in that no exercise of Agency discretion is required. This process will rely on notices of availability of the relevant data in the **Federal Register**, coupled with an opportunity for the public to correct any errors they may identify in the data before the EPA sets each updated budget. See section VI.B.4 for more detail on how the EPA intends to implement dynamic budgeting. As in prior transport rules, this rule provides the opportunity for administrative appeal should an interested party identify some flaw in the EPA's updated data. See 40 CFR 78.1(b)(19)(i) (2023). That process is coupled with the availability of judicial review should the party remain dissatisfied with the EPA's resolution of complaints. *See* 40 CFR 78.1(a)(2) (requiring administrative adjudication as a prerequisite for judicial review). This administrative process has worked well throughout the history of implementing good neighbor trading programs under Part 97, and no such disputes have necessitated judicial resolution.

Further, because the dynamic budgets simply implement the stringency level reflective of the emissions control performance the EPA has determined at Step 3 for the covered EGUs, the EPA does not agree that any ''potential variables'' that are unforeseeable now could upset the basis for the formula the EPA is establishing in this action. The EPA has adjusted the role of dynamic budgeting in this final rule as compared to the proposal. See sections VI.B.1 and VI.B.4 of the preamble. In particular, the EPA is applying an approach to budget setting through 2029 that will use the greater of either a preset budget based on information known to the Agency at the time of this action, or the dynamic budget to be calculated based upon future data yet to be reported. Thus, through 2029 the imposition of a dynamic budget would only increase rather than diminish the emissions allowed for that control period compared to the preset budgets established in this action. In addition, the EPA will determine each state's dynamic budget based on a rolling 3-year average of the state's heat input, thus smoothing out trends to account for interannual variability in demand and heat input and provide greater certainty and predictability as the budget updates from year to year.

Moreover, the EPA does not agree that the EPA is constrained by the statute to only implement good neighbor obligations through fixed, unchanging, mass-based emissions budgets. *See* section III.B.1 of this document. The EPA finds good reason based on its experience with trading programs using fixed budgets why this approach does not necessarily ensure the elimination of significant contribution in perpetuity. The EPA has already once adjusted its historical approach to better account for known, upcoming changes in the EGU fleet to ensure mass-based emissions budgets adequately incentivize the control strategy determined at Step 3. This adjustment was introduced in the Revised CSAPR Update. *See* 82 FR

23121–22.[96] The EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that the mass-based emissions budget incentivize continuing implementation of the Step 3 control strategies to ensure significant contribution is eliminated in all upwind states and remains so. The dynamic budget-setting process preserves these incentives over time by calculating the state emissions budgets for each future control period so as to reflect the Step 3 control stringency finalized in this rule as applied to the most current information regarding the composition of the power sector in the control period. This is fully analogous in material respect to an approach to implementation at Step 4 that relies on application of unit-specific emissions rates that apply in perpetuity. The availability of unit-specific emissions rates as a means to eliminate significant contribution is discussed in further detail in section III.B.1 of this document. The EPA also explained this in the proposal. *See* 87 FR 20095–96. The EPA does not agree that either dynamic budgeting or the backstop rate results in overcontrol. *See* section V.D.4 of this document.

The EPA is enhancing the trading program to help reconcile the approach of using mass-based budgets to achieve the elimination of significant contribution with the *Wisconsin* directive to provide a complete remedy under the good neighbor provision. This approach also better accords with ensuring measures to attain and maintain the NAAQS are permanent and enforceable. The dynamic budget approach recognizes that the uncertainty around future fleet conditions increases the further into the future one looks (and the EPA must look further under the ''full remedy'' directive). To preserve its ability to successfully implement its identified Step 3 stringency, the EPA is designing the implementation of this rule's emissions control program to benefit from the future availability of better data from the regulated sources to inform its application of its stringency measures identified in this rule.

The EPA does not agree with commenters who suggest that these enhancements are undertaken for the purpose of a non-statutory ''environmental justice'' objective. As explained in section VI.B of this document, certain enhancements to the trading program ensure that each EGU is adequately incentivized to continuously operate its emissions controls once those controls are installed. One commenter contends that the backstop emissions rate is not authorized based on environmental justice considerations, since it is not necessary and is overcontrol with respect to the EPA's statutory authority to address good neighbor obligations. But the EPA disagrees with the premise that these enhancements are unrelated to the statutory obligation to eliminate significant contribution. Taking measures to ensure that each upwind source covered by an emissions trading program to eliminate significant contribution is operating its installed pollution controls on a more continuous and consistent basis throughout the ozone season is entirely appropriate in light of the daily nature of the ozone problem, the impacts to public health and the environment from ozone that can occur through short-term exposure (*e.g.,* over a course of hours), the fact that the 2015 ozone NAAQS is expressed as an 8-hour average, and that only a small number of days in excess of the ozone NAAQS are necessary to place a downwind area in nonattainment, resulting in continuing and/or increased regulatory burden on the downwind jurisdiction. *See* section III.A of this document.

Further, the D.C. Circuit has held that the EPA must ensure that its good neighbor program has eliminated *each* state's sources from continuing to significantly contribute to nonattainment or interfere with maintenance in downwind states. *See North Carolina,* 531 F.3d at 921. The commenters neglect to acknowledge the scenario that has frequently borne out in prior programs, in which future fleet changes that were not known at the time of initial setting of state emissions budgets produce unexpected ''hot air'' in the budget that, if unaccounted for, other units can exploit to forgo identified cost-effective mitigation measures deemed necessary to eliminate significant contribution to nonattainment and interference with maintenance of the NAAQS.

The EPA's experience is that fixed mass-based budgets that are determined based only on the profile of the power sector at the time the rule is promulgated, and without any additional requirement for pollution controls operation, can become quickly obsolete if the composition of the group of affected EGUs changes notably over time. As some sources retire, other sources relax their operation of NO_X controls in response to a growing surplus of allowances, even though the EPA had concluded that ongoing operation of those controls is necessary to meet the statutory good neighbor requirements. For instance, under the CSAPR Update, in the 2018–2020 period, the fixed budget approach enabled large, frequently run units with existing SCR controls to not optimize those controls even though the EPA's assessment (as reflected in the CSAPR Update) was that the optimization of those controls was necessary to eliminate significant contribution. This deterioration in emission rate at SCR-controlled coal plants was widely observed across the CSAPR Update geography as the program advanced into later years and allowance price deteriorated. Whereas coal sources with SCR performed, on average, at a 0.086 lb/mmBtu rate in 2017, that same set of sources saw their environmental performance worsen to a 0.099 lb/mmBtu rate in 2020. A Congressional Research Service Report on EPA prior CSAPR trading programs indicated low prices observed in later years ''could lead to some decisions not to run some pollution controls at maximum output. This would, in turn, lead to higher emissions''.[97]

In the case of individual units, this deterioration in performance can be quite pronounced and can occur as quickly as the second or third control period, as in the case of Miami Fort Unit 7 in Ohio in 2019, discussed in section V.B of this document. The absence of a sufficient incentive under the trading program to implement the identified control strategy at Step 3 can even result in collective emissions that exceed state-wide assurance levels. The EPA established these levels beginning with CSAPR, above which enhanced allowance-surrender requirements are triggered, in an effort to ensure sources in each state are held to eliminate their own significant contribution, which the D.C. Circuit has held is legally required, *see North Carolina,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). In four instances over the course of the 2019, 2020, and

[96] Further, in the Revised CSAPR Update, the EPA acknowledged that a mechanism like dynamic budgeting could be appropriate for a transport rule with longer time horizons. We stated in response to comments that we were not ''in this action, including an adjustment mechanism to further adjust state emission budgets to account for currently unknown or uncertain retirements after the finalization of this rule . . . . EPA observes that the commenter's proposed mechanism would become increasingly valuable for rules where the timeframe extends further into the future where retirement uncertainty is higher.'' Revised CSAPR Update Response to Comments, EPA–HQ–OAR–2020–0272–219, at 153.

[97] Shouse, Kate. ''The Clean Air Act's Good Neighbor Provision: Overview of Interstate Air Pollution Control''. Congressional Research Services. August 30, 2018. Available at *https://sgp.fas.org/crs/misc/R45299.pdf.*

2021 control periods under the CSAPR Update, sources in Mississippi and Missouri collectively exceeded their state-wide assurance levels in part due to deterioration in emissions performance that can be attributed to a glut of allowances within the CSAPR Update. See section VI.B.8 of the preamble.

Thus, while this trading program structure may achieve some environmental benefit through fixed emissions budgets for initial control periods, over time those fixed budgets cease to have their intended effect, and remaining operating facilities can, and have, increased emissions or even discontinued the operation of their emissions controls. This, in turn, can lead to the continuation (or re-emergence) of significant contribution in terms of a recurrence of excessive emissions that had been slated for permanent elimination under the EPA's determinations at Step 3. Although the EPA has always intended for its trading programs to provide flexibility, the Agency did not expect and has certainly never endorsed the use of that flexibility to stop the operation of controls that have already been installed. *See, e.g.,* 76 FR 48256–57 (''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).''). Despite the EPA's expectations in CSAPR, the historical data establishes a real risk of ''under-control'' if the existing trading framework is not improved upon. *See EME Homer City,* 572 U.S. at 523 (''[T]he Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'').

This result is also inconsistent with the statutory mandate to ''prohibit'' significant contribution and interference with maintenance of the NAAQS in downwind states, as evidenced most clearly in CAA section 126, which makes it unlawful for a source ''to *operate* more than three months after [a finding that the source emits or would emit in violation of the good neighbor provision] has been made with respect to it.'' 42 U.S.C. 7426(c)(2) (emphasis added). *See also North Carolina,* 531 F.3d at 906–08 (each state must be held to the elimination of its own significant contribution). The purpose of the Agency's interstate trading programs under the good neighbor provision is to afford sources some flexibility in achieving region-wide emissions reductions; however, there is no justification that can be sustained within that framework for sources in certain areas within that region, or during periods of high ozone when good emissions performance is most essential, to emit at levels well in excess of the EPA's Step 3 determinations of significant contribution. Significant contribution, according to the statute, must be ''prohibited.'' CAA section 110(a)(2)(D)(i).

Thus, these trading program enhancements are within the EPA's authority under CAA section 110(a)(2)(D)(i)(I) to eliminate interstate ozone pollution that significantly contributes to nonattainment or interferes with maintenance in downwind states. These enhancements ensure the elimination of significant contribution across all upwind states and throughout each ozone season. We observe in the Ozone Transport Policy Analysis Final Rule TSD, section E, that the trading program enhancements may also benefit underserved and overburdened communities downwind of EGUs in the covered geography of the final rule. See section VI.B of this document. This does not detract from the statutorily-authorized basis for these changes, and the EPA finds nothing impermissible in acknowledging the reality of these potential benefits for underserved and overburdened communities.

The EPA appreciates a commenter's concern that our actions be legally defensible. The EPA acknowledges that the changes to the trading program structure for implementing good neighbor obligations discussed here constitute a change in the policy underlying its prior transport-rule trading programs for EGUs. However, the EPA is confident that these changes are in compliance with the holdings in judicial decisions reviewing prior transport rules. The fact that the EPA is making changes does not somehow render these enhancements legally impermissible or even subject to a heightened standard of review. *See FCC* v. *Fox Television Stations,* 556 U.S. 502, 514 (2009) (''We find no basis in the Administrative Procedure Act or in our opinions for a requirement that all agency change be subjected to more searching review.''). We have explained previously and elsewhere in the record that there are ''good reasons'' for the ''new policy.'' *See id.* at 515. And, we are of course fully aware that we have changed our position. *See id.* at 514–15. Specifically, we have gone from previously treating fixed, mass-based budgets as sufficient to eliminate significant contribution, to an approach for purposes of the 2015 ozone NAAQS reflecting a more nuanced understanding of how an emissions trading program that does not properly anticipate future fleet conditions at Step 4 may fail to achieve the elimination of emissions that should be prohibited based on our findings at Step 3. Further, we find there to be no ''serious reliance interests'' that have been or even could have been ''engendered'' by any prior policy on these issues, *see id.* at 515–16. The EPA is implementing these enhancements for the first time with respect to a new obligation—good neighbor requirements for the 2015 ozone NAAQS. No party reasonably could have invested substantial resources to-date to comply with an obligation that was heretofore undefined; and no commenter has supplied any information to the contrary.

2. FIP Authority for Each State Covered by the Rule

On October 26, 2015, the EPA promulgated a revision to the 2015 8-hour ozone NAAQS, lowering the level of both the primary and secondary standards to 0.070 parts per million (ppm).[98] These revisions of the NAAQS, in turn, established a 3-year deadline for states to provide SIP submissions addressing infrastructure requirements under CAA sections 110(a)(1) and CAA 110(a)(2), including the good neighbor provision, by October 1, 2018. If the EPA makes a determination that a state failed to submit a SIP, or if EPA disapproves a SIP submission, then the EPA is obligated under CAA section 110(c) to promulgate a FIP for that state within 2 years. For a more detailed discussion of CAA section 110 authority and timelines, refer to section III.C of this document.

The EPA is finalizing this FIP action now to address 23 states' good neighbor obligations for the 2015 ozone NAAQS.[99] For each state for which the EPA is finalizing this FIP, the EPA either issued final findings of failure to submit or has issued a final disapproval of that state's SIP submission.

Several commenters asserted that the sequence of the EPA's actions, and in particular, the timing of its proposed FIP (which was signed on February 28,

[98] *National Ambient Air Quality Standards for Ozone,* Final Rule, 80 FR 65292 (Oct. 26, 2015). Although the level of the standard is specified in the units of ppm, ozone concentrations are also described in parts per billion (ppb). For example, 0.070 ppm is equivalent to 70 ppb.

[99] The EPA notes that it is subject to, and has met through this action, a consent decree deadline to promulgate FIPs addressing 2015 ozone NAAQS good neighbor obligations for the states of Pennsylvania, Utah, and Virginia. *See Sierra Club et al.* v. *Regan,* No. 3:22–cv–01992–JD (N.D. Cal. entered January 24, 2023).

2022, and published on April 6, 2022) in relation to the timing of its proposed SIP disapprovals (most of which were published on February 22, 2022, four of which were published on May 24, 2022, and one of which was published on October 25, 2022), was either unlawful or unreasonable in light of the sequence of steps required under CAA section 110(k) and (c).

These commenters are incorrect. As an initial matter, concerns about the timing or substance of the EPA's actions on the SIP submittals are beyond the scope of this action. Nor are the timing or contents of merely proposed actions to be considered final agency actions or subject to judicial review. *See In re Murray Energy,* 788 F.3d 330 (D.C. Cir. 2015). With these principles in mind, the timing of this final action is lawful under the Act. First, the EPA is not required to wait to propose a FIP until after the Agency proposes or finalizes a SIP disapproval or makes a finding of failure to submit.[100] CAA section 110(c) authorizes the EPA to promulgate a FIP ''at any time within 2 years'' of a SIP disapproval or making a finding of failure to submit. The Supreme Court recognized in *EME Homer City* that the EPA is not obligated to first define a state's good neighbor obligations or give the state an additional opportunity to submit an approvable SIP before promulgating a FIP: ''EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP 'at any time' within the two-year limit.'' [101] Thus, the EPA may promulgate a FIP contemporaneously with or immediately following predicate final SIP disapproval (or finding no SIP was submitted). To accomplish this, the EPA must necessarily be able to propose a FIP prior to taking final action to disapprove a SIP or make a finding of failure to submit.

Second, and more importantly, the EPA has established predicate authority to promulgate FIPs for all of the covered states through its action with respect to the relevant SIP submittals. A brief history of these actions follows:

On February 22, 2022, the EPA proposed to disapprove 19 good neighbor SIP submissions (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, West Virginia, Wisconsin).[102] Alabama subsequently withdrew its SIP submission and re-submitted a SIP submission on June 22, 2022. The EPA proposed to disapprove that SIP submittal on October 25, 2022.[103] The EPA proposed to disapprove good neighbor SIP submissions for four additional states, California, Nevada, Utah, and Wyoming, on May 24, 2022.[104]

Subsequently, on January 31, 2023, the EPA Administrator signed a single disapproval action for all of the above states, with the exception of Tennessee and Wyoming.[105] This action established the EPA's authority to promulgate FIPs for the disapproved states. (As explained in section IV.F of this document, the Agency is deferring action at this time for Tennessee and Wyoming with respect to its proposed FIP actions for those states. As discussed in section IV.F of this document, the EPA's most recent modeling and air quality analysis indicates that several states may be linked to downwind receptors for which we had not previously proposed disapproval or FIP action. The EPA anticipates addressing remaining interstate transport obligations for the 2015 ozone NAAQS for these in a subsequent rulemaking.)

Additionally, the EPA has taken action that has triggered the EPA's obligation under CAA section 110(c) to promulgate FIPs addressing the good neighbor provision for several downwind states. On December 5, 2019, the EPA published a rule finding that seven states (Maine, New Mexico, Pennsylvania, Rhode Island, South Dakota, Utah, and Virginia) failed to submit or otherwise make complete submissions that address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.[106] This finding triggered a 2-year deadline for the EPA to issue FIPs to address the good neighbor provision for these states by January 6, 2022. As the EPA has subsequently received and taken final action to approve good neighbor SIPs from Maine, Rhode Island, and South Dakota,[107] the EPA currently has authority under the December 5, 2019, findings of failure to submit to issue FIPs for New Mexico, Pennsylvania, Utah, and Virginia. In this final rule, the EPA is issuing FIP requirements for Pennsylvania, Utah, and Virginia.[108]

Further information on the procedural history establishing the EPA's authority for this final rule is provided in a document in the docket.[109]

[100] The EPA notes there are three consent decrees to resolve three deadline suits related to EPA's duty to act on good neighbor SIP submissions for the 2015 ozone NAAQS. In *New York et al.* v. *Regan, et al.* (No. 1:21–CV–00252, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Indiana, Kentucky, Michigan, Ohio, Texas, and West Virginia by April 30, 2022; however, if the EPA proposes to disapprove any SIP submissions and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on that SIP submission is extended to December 30, 2022. In *Downwinders at Risk et al.* v. *Regan* (No. 21–cv–03551, N.D. Cal.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Alabama, Arkansas, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee, Texas, West Virginia, and Wisconsin by April 30, 2022; however, if the EPA proposes to disapprove any of these SIP submissions and proposes a replacement FIP by February 28, 2022, then the EPA's deadline to take final action on that SIP submission is December 30, 2022. In this CD, the EPA also agreed to take final action on Hawaii's SIP submission by April 30, 2022, and to take final action on the SIP submissions of Arizona, California, Montana, Nevada, and Wyoming by December 15, 2022. In *Our Children's Earth Foundation* v. *EPA* (No. 20–8232, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submission from New York by April 30, 2022; however, if the EPA proposes to disapprove New York's SIP submission and proposes a replacement FIP by February 28, 2022, then the EPA's deadline to take final action on New York's SIP submission is extended to December 30, 2022. By stipulation of the parties, the December 15, 2022, date in all three of these consent decrees was extended to January 31, 2023. By further stipulation of the parties in the *Downwinders at Risk* case, the January 31, 2023, date was further extended to December 15, 2023 for the EPA to act on the SIP submissions from the states of Arizona, Tennessee, and Wyoming.

[101] *See EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489, 509 (2014) (citations omitted).

[102] *See* 87 FR 9463 (Maryland); 87 FR 9484 (New Jersey, New York); 87 FR 9498 (Kentucky); 87 FR 9516 (West Virginia); 87 FR 9533 (Missouri); 87 FR 9545 (Alabama, Mississippi, Tennessee); 87 FR 9798 (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9838 (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin).

[103] *See* 87 FR 64412.

[104] *See* 87 FR 31443 (California); 87 FR 31485 (Nevada); 87 FR 31470 (Utah); 87 FR 31495 (Wyoming).

[105] *See* 88 FR 9336.

[106] *Findings of Failure To Submit a Clean Air Act Section 110 State Implementation Plan for Interstate Transport for the 2015 Ozone National Ambient Air Quality Standards (NAAQS),* 84 FR 66612 (December 5, 2019, effective January 6, 2020).

[107] *Air Plan Approval; Maine and New Hampshire; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 45870 (August 17, 2021); *Air Plan Approval; Rhode Island; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 70409 (December 10, 2021); *Promulgation of State Implementation Plan Revisions; Infrastructure Requirements for the 2015 Ozone National Ambient Air Quality Standards; South Dakota; Revisions to the Administrative Rules of South Dakota,* 85 FR 29882 (May 19, 2020).

[108] *WildEarth Guardians* v. *Regan,* No. 1:22–cv–00174 (D.N.M. entered Aug. 16, 2022); *Sierra Club et al.* v. *EPA,* No. 3:22–cv–01992 (N.D. Cal. entered Jan. 24, 2023).

[109] *See* ''Final Rule: Status of CAA Section 110(a)(2)(D)(i)(I) SIP Submissions for the 2015 Ozone NAAQS for States Covered by the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards.'' This document updates a prior document of the same title provided

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While the EPA's previous actions are sufficient to establish that the EPA's promulgation of this FIP action at this time is lawful, the timing of this action is all the more reasonable in light of the need for the EPA to address good neighbor obligations consistent with the rest of title I of the CAA. In particular, the D.C. Circuit in *Wisconsin* held that states and the EPA are obligated to fully address good neighbor obligations for ozone ''as expeditiously as practical'' and in no event later than the next relevant downwind attainment dates found in CAA section 181(a).[110] In *Maryland* v. *EPA,* the D.C. Circuit made clear that *Wisconsin'*s and *North Carolina'*s holdings are fully applicable to the Marginal area attainment date for the 2015 ozone NAAQS,[111] which fell on August 3, 2021.[112] As discussed in section VI.A of this document, by finalizing this action now, the EPA is able to implement initial required emissions reductions to eliminate significant contribution by the 2023 ozone season, which is the last full ozone season before the next attainment date, the Moderate area attainment date of August 3, 2024. The *Wisconsin* court emphasized that the EPA has the authority under CAA section 110 to structure and time its actions in a manner such that the Agency can ensure necessary reductions are achieved in alignment with the downwind attainment schedule, and that is precisely what the EPA is doing here.[113] The EPA provides further response to the comments on this issue in section 1 of the *RTC* document.

C. Other CAA Authorities for This Action

1. Withdrawal of Proposed Error Correction for Delaware

The EPA proposed at 87 FR 20036 to make an error correction under CAA section 110(k)(6) of its May 1, 2020, approval at 85 FR 25307 of the interstate transport elements for Delaware's October 11, 2018, and December 26, 2019, ozone infrastructure SIP submissions as satisfying the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. The EPA proposed to determine that the basis for the prior SIP approval was invalidated by the Agency's more recent technical evaluation of air quality modeling performed in support of the proposed rule,[114] and that Delaware had unresolved interstate transport obligations for the 2015 ozone NAAQS. The EPA also proposed to issue a FIP for Delaware given these unresolved interstate transport obligations. However, based on the updated air quality modeling described in section IV.F. of this document and the technical assessment that informs this final rule, the EPA finds that Delaware is not projected to be linked to any downwind receptor above the 1 percent of the NAAQS threshold in 2023. Thus, based on the record before the Agency now, the original approval of Delaware's SIP submission was not in error, and the EPA is withdrawing its proposed error correction and proposed FIP for Delaware.

2. Application of Rule in Indian Country and Necessary or Appropriate Finding

The EPA is finalizing its determination that this rule will be applicable in all areas of Indian country (as defined at 18 U.S.C. 1151) within the covered geography of the final rule, as defined in this section. Certain areas of Indian country within the geography of the rule are or may be subject to state implementation planning authority. Other areas of Indian country within that geography are subject to tribal planning authority, although none of the relevant tribes have as yet sought eligibility to administer a tribal plan to implement the good neighbor provision.[115] As described later, the EPA is including all areas of Indian country within the covered geography, notwithstanding whether those areas are currently subject to a state's implementation planning authority or the potential planning authority of a tribe.

a. Indian Country Subject to Tribal Jurisdiction

With respect to areas of Indian country not currently subject to a state's implementation planning authority—*i.e.,* Indian reservation lands (with the partial exception of reservation lands located in the State of Oklahoma, as described further in this section) and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction—the EPA here makes a ''necessary or appropriate'' finding that direct Federal implementation of the rule's requirements is warranted under CAA section 301(d)(4) and 40 CFR 49.11(a) (the areas of Indian country subject to this finding will be referred to as the CAA section 301(d) FIP areas). Indian Tribes may, but are not required to, submit tribal plans to implement CAA requirements, including the good neighbor provision. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (*i.e.,* TAS) for purposes of developing and implementing a tribal plan implementing good neighbor obligations. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule'' (63 FR 7254, February 12, 1998). The EPA is authorized to directly implement the good neighbor provision in the 301(d) FIP areas when it finds, consistent with the authority of CAA section 301—which the EPA has exercised in 40 CFR 49.11—that it is necessary or appropriate to do so.[116]

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at proposal (Document no. EPA–HQ–OAR–2021–0668–0131).

[110] *Wisconsin* v. *EPA,* 938 F.3d 303, 313–14 (D.C. Cir. 2019) (citing *North Carolina* v. *EPA,* 531 F.3d 896, 911–13 (D.C. Cir. 2008).

[111] *Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[112] *See* CAA section 181(a); 40 CFR 51.1303; *Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards,* 83 FR 25776 (June 4, 2018, effective August 3, 2018).

[113] 938 F.3d at 318 (''When EPA determines a State's SIP is inadequate, EPA presumably must issue a FIP that will bring that State into compliance before upcoming attainment deadlines, even if the outer limit of the statutory timeframe gives EPA more time to formulate the FIP.'') (citing *Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002)).

[114] *See* the Air Quality Modeling Proposed Rule TSD in the docket for this rule.

[115] We note that, consistent with the EPA's prior good neighbor actions in California, the regulatory ozone monitor located on the Morongo Band of Mission Indians (''Morongo'') reservation is a projected downwind receptor in 2023. *See* monitoring site 060651016 in Table IV.D.–1. We also note that the Temecula, California, regulatory ozone monitor is a projected downwind receptor in 2023 and in past regulatory actions has been deemed representative of air quality on the Pechanga Band of Luiseño Indians (''Pechanga'') reservation. *See, e.g., Approval of Tribal Implementation Plan and Designation of Air Quality Planning Area; Pechanga Band of Luiseño Mission Indians,* 80 FR 18120, at 18121–18123 (April 3, 2015); *see also* monitoring site 060650016 in Table IV.D–1. The presence of receptors on, or representative of, the Morongo and Pechanga reservations does not trigger obligations for the Morongo and Pechanga Tribes. Nevertheless, these receptors are relevant to the EPA's assessment of any linked upwind states' good neighbor obligations. *See, e.g., Approval and Promulgation of Air Quality State Implementation Plans; California; Interstate Transport Requirements for Ozone, Fine Particulate Matter, and Sulfur Dioxide,* 83 FR 65093 (December 19, 2018). Under 40 CFR 49.4(a), tribes are not subject to the specific plan submittal and implementation deadlines for NAAQS-related requirements, including deadlines for submittal of plans addressing transport impacts.

[116] *See Arizona Pub. Serv. Co.* v. *U.S. E.P.A.,* 562 F.3d 1116, 1125 (10th Cir. 2009) (stating that 40 CFR 49.11(a) ''provides the EPA discretion to determine what rulemaking is necessary or appropriate to protect air quality and requires the EPA to promulgate such rulemaking''); *Safe Air For Everyone* v. *U.S. Env't Prot. Agency,* No. 05–73383, 2006 WL 3697684, at *1 (9th Cir., Dec. 15, 2006) (''The statutes and regulations that enable EPA to regulate air quality on Indian reservations provide EPA with broad discretion in setting the content of such regulations.'').

The EPA hereby finds that it is both necessary and appropriate to regulate all new and existing EGU and industrial sources meeting the applicability criteria set forth in this rule in all of the 301(d) FIP areas that are located within the geographic scope of coverage of the rule. For purposes of this finding, the geographic scope of coverage of the rule means the areas of the United States encompassed within the borders of the states the EPA has determined to be linked at Steps 1 and 2 of the 4-step interstate transport framework.[117] For EGU applicability criteria, *see* section VI.B of this document; for industrial-source applicability criteria, *see* section VI.C of this document. To EPA's knowledge, only one existing EGU or industrial source is located within the CAA section 301(d) FIP areas: the Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah.

This finding is consistent with the EPA's prior good neighbor rules. In prior rulemakings under the good neighbor provision, the EPA has included all areas of Indian country within the geographic scope of those FIPs, such that any new or existing sources meeting the rules' applicability criteria would be subject to the rule irrespective of whether subject to state or tribal underlying CAA planning authority. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the scope of the emissions trading programs established for EGUs extended to cover all areas of Indian country located within the geographic boundaries of the covered states. In these rules, at the time of their promulgation, no existing units were located in the covered areas of Indian country; under the general applicability criteria of the trading programs, however, any new sources locating in such areas would become subject to the programs. Thus, the EPA established a separate allowance allocation that would be available for any new units locating in any of the relevant areas of Indian country. *See, e.g.,* 76 FR 48293 (describing the CSAPR methodology of allowance allocation under the ''Indian country new unit set-aside'' provisions); *see also id.* at 48217 (explaining the EPA's source of authority for directly regulating in relevant areas of Indian country as necessary or appropriate). Further, in any action in which the EPA subsequently approved a state's SIP submittal to partially or wholly replace the provisions of a CSAPR FIP, the EPA has clearly delineated that it will continue to administer the Indian country new unit set aside for sources in any areas of Indian country geographically located within a state's borders and not subject to that state's CAA planning authority, and the state may not exercise jurisdiction over any such sources. *See, e.g.,* 82 FR 46674, 46677 (October 6, 2017) (approving Alabama's SIP submission establishing a state CSAPR trading program for ozone season NO_X, but providing, ''The SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction.'').

In this rule, the EPA is taking an approach similar to the prior CSAPR rulemakings with respect to regulating sources in the CAA section 301(d) FIP areas.[118] The EPA believes this approach is necessary and appropriate for several reasons. First, the purpose of this rule is to address the interstate transport of ozone on a national scale, and the technical record establishes that the nonattainment and maintenance receptors located throughout the country are impacted by sources of ozone pollution on a broad geographic scale. The upwind regions associated with each receptor typically span at least two, and often far more, states. Within the broad upwind region covered by this rule, the EPA is applying—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO_X SIP Call—a uniform level of control stringency (as determined separately for linkages existing in 2023, and linkages persisting in 2026). (*See* section V of this document for a discussion of EPA's determination of control stringency for this rule.) Within this approach, consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is, in the words of the Supreme Court, ''efficient and equitable,'' 572 U.S. 489, 519. In particular, as the Supreme Court found in *EME Homer City Generation,* allocating responsibility through uniform levels of control across the entire upwind geography is ''equitable'' because, by imposing uniform cost thresholds on regulated States, the EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to reduce their emissions by installing devices of the kind in which neighboring States have already invested. *Id.*

In the context of addressing regional-scale ozone transport in this rule, the importance of a uniform level of stringency that extends to and includes the CAA section 301(d) FIP areas geographically located within the boundaries of the linked upwind states carries significant force. Failure to include all such areas within the scope of the rule creates a significant risk that these areas may be targeted for the siting of facilities emitting ozone-precursor pollutants, to avoid the regulatory costs that would be imposed under this rule in the surrounding areas of state jurisdiction. Electricity generation or the production of other goods and commodities may become more cost-competitive at any EGU or industrial sources not subject to the rule but located in a geography where the same types of sources are subject to the rule. For instance, the affected EGU source located on the Uintah and Ouray Reservation of the Ute Tribe is in an area that is interconnected with the western electricity grid and is owned and operated by an entity that generates and provides electricity to customers in several states. It is both necessary and appropriate, in the EPA's view, to avoid creating, via this rule, a structure of incentives that may cause generation or production—and the associated NO_X emissions—to shift into the CAA section 301(d) FIP areas to escape regulation needed to eliminate interstate transport under the good neighbor provision.

The EPA finds it is appropriate to directly implement the rule's requirements in the CAA section 301(d) FIP areas in this action rather than at a later date. Tribes have the opportunity to seek treatment as a state (TAS) and to undertake tribal implementation plans under the CAA. To date, the one tribe which could develop and seek approval of a tribal implementation plan to address good neighbor obligations with respect to an existing EGU in the CAA section 301(d) FIP areas for the 2015 ozone NAAQS (or for any other NAAQS), the Ute Indian Tribe of the Uintah and Ouray Reservation, has not

[117] With respect to any industrial sources located in the CAA section 301(d) FIP areas, the geographic scope of coverage of this rule does not include those states for which the EPA finds, based on air quality modeling, that no further linkage exists by the 2026 analytic year at Steps 1 and 2. The states in this rule not linked in 2026 are Alabama, Minnesota, and Wisconsin.

[118] *See* section VI.B.9 of this document for a discussion of revisions that are being made in this rulemaking regarding the point in the allowance allocation process at which the EPA would establish set-asides of allowances for units in Indian country not subject to a state's CAA implementation planning authority.

expressed an intent to do so. Nor has the EPA heard such intentions from any other tribe, and it would not be reasonable to expect tribes to undertake that planning effort, particularly when no existing sources are currently located on their lands. Further, the EPA is mindful that under court precedent, the EPA and states bear an obligation to fully implement any required emissions reductions to eliminate significant contribution under the good neighbor provision as expeditiously as practicable and in alignment with downwind areas' attainment schedule under the Act. As discussed in section VI.A of this document, the EPA is implementing certain required emissions reductions by the 2023 ozone season, the last full ozone season before the 2024 Moderate area attainment date, and other key additional required emissions reductions by the 2026 ozone season, the last full ozone season before the 2027 Serious area attainment date. Absent the application of this FIP in the CAA section 301(d) FIP areas, NO_X emissions from any existing or new EGU or non-EGU sources located in, or locating in, the CAA section 301(d) FIP areas within the covered geography of the rule would remain unregulated for purposes of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS and could continue or potentially increase. This would be inconsistent with the EPA's overall goal of aligning good neighbor obligations with the downwind areas' attainment schedule and to achieve emissions reductions as expeditiously as practicable.

Further, the EPA recognizes that Indian country, including the CAA section 301(d) FIP areas, is often home to communities with environmental justice concerns, and these communities may bear a disproportionate level of pollution burden as compared with other areas of the United States. The EPA's Fiscal Year 2022–2026 Strategic Plan [119] includes an objective to promote environmental justice at the Federal, Tribal, state, and local levels and states: ''Integration of environmental justice principles into all EPA activities with Tribal governments and in Indian country is designed to be flexible enough to accommodate EPA's Tribal program activities and goals, while at the same time meeting the Agency's environmental justice goals.'' As described in section X.F of this document, the EPA offered Tribal consultation to 574 Tribes in April of 2022 and received no requests for Tribal consultation after publication of the proposed rulemaking. By including all areas of Indian country within the covered geography of the rule, the EPA is advancing environmental justice, lowering pollution burdens in such areas, and preventing the potential for ''pollution havens'' to form in such areas as a result of facilities seeking to locate there to avoid the requirements that would otherwise apply outside of such areas under this rule.

Therefore, to ensure timely alignment of all needed emissions reductions within the timetables of this rule, to ensure equitable distribution of the upwind pollution reduction obligation across all upwind jurisdictions, to avoid perverse economic incentives to locate sources of ozone-precursor pollution in the CAA section 301(d) FIP areas, and to deliver greater environmental justice to tribal communities in line with Executive Order 13985: Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,[120] the EPA finds it both necessary and appropriate that all existing and new EGU and industrial sources that are located in the CAA section 301(d) FIP areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. The EPA issues this finding under CAA section 301(d)(4) of the Act and 40 CFR 49.11. Further, to avoid ''unreasonable delay'' in promulgating this FIP, as required under section 49.11, the EPA makes this finding now, to align emissions reduction obligations for any covered new or existing sources in the CAA section 301(d) FIP areas with the larger schedule of reductions under this rule. Because all other covered EGU and non-EGU sources within the geography of this rule would be subject to emissions reductions of uniform stringency beginning in the 2023 ozone season, and as necessary to fully and expeditiously address good neighbor obligations for the 2015 ozone NAAQS, there is little benefit to be had by not including the CAA section 301(d) FIP areas in this rule now and a potentially significant downside to not doing so.

The Agency recognizes that Tribal governments may still choose to seek TAS to develop a Tribal plan with respect to the obligations under this rule, and this determination does not preclude the tribes from taking such actions. Although the formal tribal consultation process associated with this action has concluded, the EPA is willing and available to engage with any tribe as this rule is implemented.

b. Indian Country Subject to State Implementation Planning Authority

Following the U.S. Supreme Court decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020), the Governor of the State of Oklahoma requested approval under section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005: A Legacy for Users, Public Law 109–59, 119 Stat. 1144, 1937 (August 10, 2005) (''SAFETEA''), to administer in certain areas of Indian country (as defined at 18 U.S.C. 1151) the State's environmental regulatory programs that were previously approved by the EPA for areas outside of Indian country. The State's request excluded certain areas of Indian country further described later. In addition, the State only sought approval to the extent that such approval is necessary for the State to administer a program in light of *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014).[121]

On October 1, 2020, the EPA approved Oklahoma's SAFETEA request to administer all the State's EPA-approved environmental regulatory programs, including the Oklahoma SIP, in the requested areas of Indian country.[122] As requested by Oklahoma, the EPA's approval under SAFETEA does not include Indian country lands, including rights-of-way running through the same, that: (1) qualify as Indian allotments, the Indian titles to which have not been extinguished, under 18 U.S.C. 1151(c); (2) are held in trust by the United States on behalf of an individual Indian or Tribe; or (3) are owned in fee by a Tribe, if the Tribe (a) acquired that fee title to such land, or an area that included such land, in accordance with a treaty with the United States to which such Tribe was a party, and (b) never allotted the land to a member or citizen of the Tribe

[119] *https://www.epa.gov/system/files/documents/2022-03/fy-2022-2026-epa-strategic-plan.pdf.*

[120] Executive Order 13985 (January 20, 2021) (86 FR 7009 (January 25, 2021)): *https://www.govinfo.gov/content/pkg/FR-2021-01-25/pdf/2021-01753.pdf.*

[121] In *ODEQ* v. *EPA,* the D.C. Circuit held that under the CAA, a state has the authority to implement a SIP in non-reservation areas of Indian country in the state, where there has been no demonstration of tribal jurisdiction. Under the D.C. Circuit's decision, the CAA does not provide authority to states to implement SIPs in Indian reservations. *ODEQ* did not, however, substantively address the separate authority in Indian country provided specifically to Oklahoma under SAFETEA. That separate authority was not invoked until the State submitted its request under SAFETEA, and was not approved until the EPA's decision, described in this section, on October 1, 2020.

[122] Available in the docket for this rulemaking.

(collectively ''excluded Indian country lands'').

The EPA's approval under SAFETEA expressly provided that to the extent EPA's prior approvals of Oklahoma's environmental programs excluded Indian country, any such exclusions are superseded for the geographic areas of Indian country covered by the EPA's approval of Oklahoma's SAFETEA request.[123] The approval also provided that future revisions or amendments to Oklahoma's approved environmental regulatory programs would extend to the covered areas of Indian country (without any further need for additional requests under SAFETEA).

In a **Federal Register** document published on February 13, 2023 (88 FR 9336), the EPA disapproved the portion of an Oklahoma SIP submittal pertaining to the state's interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. Consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA* and with the EPA's October 1, 2020 SAFETEA approval, the EPA has authority under CAA section 110(c) to promulgate a FIP as needed to address the disapproved aspects of Oklahoma's good neighbor SIP submittal.[124] In accordance with the previous discussion, the EPA's FIP authority in this circumstance extends to all Indian country in Oklahoma, other than the excluded Indian country lands, as described previously.[125] Because—per the State's request under SAFETEA—EPA's October 1, 2020 approval does not displace any SIP authority previously exercised by the State under the CAA as interpreted in *ODEQ* v. *EPA,* the EPA's FIP authority under CAA section 110(c) also applies to any Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority. The EPA's FIP authority under CAA section 110(c) similarly applies to Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority located in any other state within the geographic scope of this rule.

In light of the relevant legal authorities discussed above regarding the scope of the State of Oklahoma's regulatory jurisdiction under the CAA, the EPA has FIP authority under CAA section 110(c) with respect to all Indian country in Oklahoma other than excluded Indian country lands. To the extent any change occurs in the scope of Oklahoma's SIP authority in Indian country following finalization of this rule, and such change affects the exercise of FIP authority provided under section 110(c) of the Act,[126] then, to the extent any such areas would fall more appropriately within the CAA section 301(d) FIP areas as described in section III.C.2.a of this document, the EPA's necessary or appropriate finding as set forth above with respect to all other CAA section 301(d) FIP areas within the geographic scope of coverage of the rule would apply.

D. Severability

The EPA regards this action as a complete remedy, which will as expeditiously as practicable implement good neighbor obligations for the 2015 ozone NAAQS for the covered states, consistent with the requirements of the Act. *See North Carolina* v. *EPA,* 531 F.3d 896, 911–12 (D.C. Cir. 2008); *Wisconsin* v. *EPA,* 938 F.3d 303, 313–20 (D.C. Cir. 2019); *Maryland* v. *EPA,* 958 F.3d 1185, 1204 (D.C. Cir. 2020); *New York* v. *EPA,* 964 F.3d 1214, 1226 (D.C. Cir. 2020); *New York* v. *EPA,* 781 Fed. App'x 4, 7–8 (D.C. Cir. 2019) (all holding that the EPA must address good neighbor obligations as expeditiously as practicable and by no later than the next applicable attainment date). Yet should a court find any discrete aspect of this document to be invalid, the Agency believes that the remaining aspects of this rule can and should continue to be implemented to the extent possible. In particular, this action promulgates a FIP for each covered state (and, pursuant to CAA section 301(d), for each area of tribal jurisdiction within the geographic boundaries of those states). Should any jurisdiction-specific aspect of the final rule be found invalid, the EPA views this rule as severable along those state and/or tribal jurisdictional lines, such that the rule can continue to be implemented as to any remaining jurisdictions. This action promulgates discrete emissions control requirements for the power sector and for each of seven other industries. Should any industry-specific aspect of the final rule be found invalid, the EPA views this rule as severable as between the different industries and different types of emissions control requirements. This is not intended to be an exhaustive list of the ways in which the rule may be severable. In the event any part of it is found invalid, our intention is that the remaining portions should continue to be implemented consistent with any judicial ruling.

The EPA's conclusion that this rule is severable also reflects the important public health and environmental benefits of this rulemaking in eliminating significant contribution and to ensure to the greatest extent possible the ability of both upwind states and downwind states and other relevant stakeholders to be able to rely on this final rule in their planning. *Cf. Wisconsin,* 938 F.3d at 336–37 (''As a general rule, we do not vacate regulations when doing so would risk significant harm to the public health or the environment.''); *North Carolina* v. *EPA,* 550 F.3d 1176, 1178 (D.C. Cir. 2008) (noting the need to preserve public health benefits); *EME Homer City* v. *EPA,* 795 F.3d 118, 132 (D.C. Cir. 2015) (noting the need to avoid disruption to emissions trading market that had developed).

IV. Analyzing Downwind Air Quality Problems and Contributions From Upwind States

A. Selection of Analytic Years for Evaluating Ozone Transport Contributions to Downwind Air Quality Problems

In this section, the EPA describes its process for selecting analytic years for air quality modeling and analyses performed to identify nonattainment and maintenance receptors and identify upwind state linkages. For this final rule, the EPA evaluated air quality to identify receptors at Step 1 for two

[123] The EPA's prior approvals relating to Oklahoma's SIP frequently noted that the SIP was not approved to apply in areas of Indian country (consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA*) located in the state. *See, e.g.,* 85 FR 20178, 20180 (April 10, 2020). Such prior expressed limitations are superseded by the EPA's approval of Oklahoma's SAFETEA request.

[124] The antecedent fact that the state had the authority and jurisdiction to implement requirements under the good neighbor provision, in the EPA's view, supplies the condition necessary for the Agency to exercise its FIP authority to the extent the EPA has disapproved the state's SIP submission with respect to those requirements. Under CAA section 110(c), the EPA ''stands in the shoes of the defaulting state, and all of the rights and duties that would otherwise fall to the state accrue instead to the EPA.'' *Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531, 1541 (9th Cir. 1993).

[125] With respect to those areas of Indian country constituting ''excluded Indian country lands'' in the State of Oklahoma, as defined supra, the EPA applies the same necessary or appropriate finding as set forth above with respect to all other 301(d) FIP areas within the geographic scope of coverage of the rule.

[126] On December 22, 2021, the EPA proposed to withdraw and reconsider the October 1, 2020, SAFETEA approval. *See https://www.epa.gov/ok/proposed-withdrawal-and-reconsideration-and-supporting-information.* The EPA is engaging in further consultation with tribal governments and expects to have discussions with the State of Oklahoma as part of this reconsideration. The EPA also notes that the October 1, 2020, approval is the subject of a pending challenge in Federal court. *Pawnee Nation of Oklahoma* v. *Regan,* No. 20–9635 (10th Cir.).

analytic years: 2023 and 2026. The EPA evaluated interstate contributions to these receptors from individual upwind states at Step 2 for these two analytic years. In selecting these years, the EPA views 2023 and 2026 to constitute years by which key emissions reductions from EGUs and non-EGUS can be implemented ''as expeditiously as practicable.'' In addition, these years are the last full ozone seasons before the Moderate and Serious area attainment dates for the 2015 ozone NAAQS (ozone seasons run each year from May 1–September 30). To demonstrate attainment by these deadlines, downwind states would be required to rely on design values calculated using ozone data from 2021 through 2023 and 2024 through 2026, respectively. By focusing its analysis, and, potentially, achieving emissions reductions by, the last full ozone seasons before the attainment dates (*i.e.,* in 2023 or 2026), this final rule can assist the downwind areas with demonstrating attainment or receiving extensions of attainment dates under CAA section 181(a)(5). (The EPA explains in detail in sections V and VI of this document its determinations regarding which emissions reduction strategies can be implemented by 2023, and which emissions reduction strategies require additional time beyond that ozone season, or the 2026 ozone season.)

It would not be logical for the EPA to analyze any earlier year than 2023. The EPA continues to interpret the good neighbor provision as forward-looking, based on Congress's use of the future-tense ''will'' in CAA section 110(a)(2)(D)(i), an interpretation upheld in *Wisconsin,* 938 F.3d at 322. It would be ''anomalous,'' *id.,* for the EPA to impose good neighbor obligations in 2023 and future years based solely on finding that ''significant contribution'' had existed at some time in the past. *Id.*

Applying this framework in the proposal, the EPA recognized that the 2021 Marginal area attainment date had already passed. Further, based on the timing of the proposal, it was not possible to finalize this rulemaking before the 2022 ozone season had also passed. Thus, the EPA has selected 2023 as the first appropriate future analytic year for this final rule because it reflects implementation of good neighbor obligations as expeditiously as practicable and coincides with the August 3, 2024, Moderate area attainment date established for the 2015 ozone NAAQS.

The EPA conducted additional analysis for 2026 to ensure a complete Step 3 analysis for future ozone transport contributions to downwind areas. As noted above, 2023 and 2026 coincide with the last full ozone seasons before future attainment dates for the 2015 ozone NAAQS. In addition, 2026 coincides with the ozone season by which key additional emissions reductions from EGUs and non-EGUs become available. Thus, the EPA analyzed additional years beyond 2023 to determine whether any additional emissions reductions that are impossible to obtain by the 2024 attainment date could still be necessary to fully address significant contribution. In all cases, implementation of necessary emissions reductions is as expeditiously as practicable, with all possible emissions reductions implemented by the next applicable attainment date.

The timing framework and selection of analytic years set forth above comports with the D.C. Circuit's direction in *Wisconsin* that implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity. *See* 938 F.3d at 320.

Comment: A commenter claims that the EPA has not followed the holdings of *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), *North Carolina* v. *EPA,* 550 F.3d 1176 (D.C. Cir. 2008), and *Maryland* v. *EPA,* 958 F. 3d 1185 (D.C. Cir. 2020) in the selection of analytic years, in that commenter interprets those decisions as holding that the EPA must ''harmonize'' the exact timing of upwind emissions reductions with when downwind states implement their required reductions. Commenter also points to the EPA's proposed action on New York's Good Neighbor SIP submission specifically to argue that the EPA is treating upwind and downwind states dissimilarly. Commenter also cites CAA sections 172, 177, and 179 to argue the EPA did not properly align upwind and downwind obligations. Several commenters believe the EPA should defer implementing good neighbor requirements until downwind receptor areas have first implemented their own emissions control strategies.

Response: The EPA maintains that 2023 is an appropriate analytic year and comports with the relevant caselaw. Section VI.A further discusses the compliance schedule for emissions reductions under this rule. Commenter misreads the *North Carolina, Wisconsin,* and *Maryland* decisions as calling for good neighbor analysis and emissions controls to be aligned with the timing of the *implementation* of nonattainment controls by downwind states. However, the D.C. Circuit has held that the *statutory attainment dates* are the relevant downwind deadlines the EPA must align with in implementing the good neighbor provision. In *Wisconsin,* the court held, ''In sum, under our decision in *North Carolina,* the Good Neighbor Provision calls for elimination of upwind States' significant contributions *on par with the relevant downwind attainment deadlines.*'' *Wisconsin,* 938 F.3d. at 321 (emphasis added).

After that decision, the EPA interpreted *Wisconsin* as limited to the attainment dates for Moderate or higher classifications under CAA section 181 on the basis that Marginal nonattainment areas have reduced planning requirements and other considerations. *See, e.g.,* 85 FR 29882, 29888–89 (May 19, 2020) (proposed approval of South Dakota's 2015 ozone NAAQS good neighbor SIP). However, on May 19, 2020, the D.C. Circuit in *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020), applying the *Wisconsin* decision, rejected that argument and held that the EPA must assess air quality at the next downwind attainment date, including Marginal area attainment dates under CAA section 181, in evaluating the basis for the EPA's denial of a petition under CAA section 126(b). 958 F.3d at 1203–04. After *Maryland,* the EPA acknowledged that the Marginal attainment date is the first attainment date to consider in evaluating good neighbor obligations. *See, e.g.,* 85 FR 67653, 67654 (Oct. 26, 2020) (final approval of South Dakota's 2015 ozone NAAQS good neighbor SIP).

The D.C. Circuit again had occasion to revisit the Agency's interpretation of *North Carolina, Wisconsin,* and *Maryland,* in a challenge to the Revised CSAPR Update brought by the Midwest Ozone Group (MOG). The court declined to entertain similar arguments to those presented by commenters here and instead in a footnote explained that it had ''exhaustively summarized the regulatory framework governing EPA's conduct'' and that it ''[drew] on those decisions and incorporate them herein by reference,'' citing, among other cases, *Maryland,* 958 F.3d 1185, and *New York,* 781 F. App'x 4. *MOG* v. *EPA,* No. 21–1146 (D.C. Cir. March 3, 2023), Slip Op. at 3 n.1.

The relevance of CAA sections 172, 177, and 179 to the selection of the analytic year in this action is not clear. Commenter cites these provisions to conclude that the EPA did not appropriately consider downwind attainment deadlines and the timing of upwind good neighbor obligations. These provisions are found in subpart I, and while they may have continuing relevance or applicability to aspects of ozone nonattainment planning requirements, the nonattainment dates for the 2015 ozone NAAQS flow from subpart 2 of title I of the CAA, and specifically CAA section 181(a). Applying that statutory schedule to the designations for the 2015 ozone NAAQS, the EPA has promulgated the applicable attainment dates in its regulations at 40 CFR 51.1303. The effective date of the initial designations for the 2015 ozone NAAQS was August 3, 2018 (83 FR 25776, June 4, 2018, effective August 3, 2018).[127] Thus, the first deadline for attainment planning under the 2015 ozone NAAQS was the Marginal attainment date of August 3, 2021, and the second deadline for attainment planning is the Moderate attainment date of August 3, 2024. If a Marginal area fails to attain by the attainment date it is reclassified, or ''bumped up,'' to Moderate. Indeed, the EPA has just completed a rulemaking action reclassifying many areas of the country from Marginal to Moderate nonattainment, including all of the areas where downwind receptors have been identified in our 2023 modeling as well as many other areas of the country. 87 FR 60897, 60899 (Oct. 7, 2022).

Other than under the narrow circumstances of CAA section 181(a)(5) (discussed further in this section), the EPA is not permitted under the CAA to extend the attainment dates for areas under a given classification. That is, no matter when or if the EPA finalizes a determination that an area failed to attain by its attainment date and reclassifies that area, the attainment date remains fixed, based on the number of years from the area's initial designation. *See, e.g.,* CAA section 182(i) (authorizing the EPA to adjust any applicable deadlines for newly reclassified areas ''other than attainment dates''). As the D.C. Circuit has repeatedly made clear, the statutory attainment schedule of the downwind nonattainment areas under subpart 2 is rigorously enforced and is not subject to change based on policy considerations of the EPA or the states.

[T]he attainment deadlines, the Supreme Court has said, are ''the heart'' of the Act. *Train* v. *Nat. Res. Def. Council,* 421 U.S. 60, 66, 95 S.Ct. 1470, 43 L.Ed.2d 731 (1975); *see Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002) (''the attainment deadlines are central to the regulatory scheme'') (alteration and internal quotation marks omitted). The Act's central object is the ''attain[ment] [of] air quality of specified standards [within] a specified period of time.'' *Train,* 421 U.S. at 64–65, 95 S.Ct. 1470.

Wisconsin, 938 F.3d at 316. *See also Natural Resources Defense Council* v. *EPA,* 777 F.3d 456, 466–68 (D.C. Cir. 2014) (holding the EPA cannot adjust the section 181 attainment schedule to run from any other date than from the date of designation); *id.* at 468 (''EPA identifies no statutory provision giving it free-form discretion to set Subpart 2 compliance deadlines based on its own policy assessment concerning the number of ozone seasons within which a nonattainment area should be expected to achieve compliance.'') (citing and quoting *Whitman* v. *American Trucking Ass'ns,* 531 U.S. 457, 484, (2001) (''The principal distinction between Subpart 1 and Subpart 2 is that the latter eliminates regulatory discretion that the former allowed.''). Furthermore, as the court in *NRDC* noted, ''[T]he 'attainment deadlines . . . leave no room for claims of technological or economic infeasibility.' '' 777 F.3d at 488 (quoting *Sierra Club,* 294 F.3d at 161) (internal quotation marks and brackets omitted).

With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899. Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* (And the New York City Metropolitan nonattainment area was initially classified as Moderate (see following text for further details).) Even if the EPA had extended the attainment date for any of the downwind areas, it is not clear that it would necessarily follow that the EPA must correspondingly extend or delay the implementation of good neighbor obligations. While the *Wisconsin* court recognized extensions under CAA section 181(a)(5) as a possible source of timing flexibility in implementing the good neighbor provision, 938 F.3d at 320, the EPA and the states are still obligated to implement good neighbor reductions as expeditiously as practicable and are also obligated under the good neighbor provision to address ''interference with maintenance.'' Areas that have obtained an extension under CAA section 181(a)(5) or which are not designated as in nonattainment could still be identified as struggling to maintain the NAAQS, and the EPA is obligated under the good neighbor provision to eliminate upwind emissions interfering with the ability to maintain the NAAQS, as well. *North Carolina,* 531 F.3d at 908–11. Thus, while an extension under CAA section 181(a)(5) may be a source of flexibility for the EPA to consider in the timing of implementation of good neighbor obligations, as *Wisconsin* recognized, it is not the case that the EPA *must* delay or defer good neighbor obligations for that reason, and neither the D.C. Circuit nor any other court has so held.

Commenter is therefore incorrect to the extent that they argue the selection of 2023 as an analytic year for upwind obligations results in the misalignment of downwind and upwind state obligations. To the contrary, both downwind and upwind state obligations are driven by the statutory attainment date of August 3, 2024 for Moderate areas, and the last year that air quality data may impact whether nonattainment areas are found to have attained by the attainment date is 2023. That is why, in the recent final rulemaking determinations that certain Marginal areas failed to attain by the attainment date, bumping those areas up to Moderate, and giving them SIP submission deadlines, reasonably available control measures (RACM), and reasonably RACT implementation deadlines, the EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. See 87 FR 60897, 60900 (Oct. 7, 2022). The implementation deadline for RACM and RACT is also January 1, 2023. *Id.* This was in large part driven by the EPA's ozone implementation regulations, 40 CFR 51.1312(a)(3)(i), which previously established a RACT implementation deadline for initially classified Moderate as no later than January 1, 2023, and the modeling and attainment demonstration requirements in 40 CFR 51.1308(d), which require a state to provide for implementation of all control measures needed for attainment no later than the beginning of the attainment year ozone season (*i.e.,* 2023). Given this regulatory history, the EPA can hardly be accused of letting states with nonattainment areas for the 2015 ozone NAAQS avoid or delay their mandatory CAA obligations.

Commenter's proposal that the EPA align good neighbor obligations with the actual implementation of measures in downwind areas is untethered from the statute, as discussed above. It is also unworkable in practice. It would necessitate coordinating the activities of multiple states and EPA regional and headquarters offices to an impossible degree and effectively could preclude the implementation of good neighbor obligations altogether. Commenter does not explain how the EPA or upwind states should coordinate upwind emissions control obligations for states

[127] September 24, 2018, for the San Antonio area. 83 FR 35136 (July 25, 2018).

linked to multiple downwind receptors whose states may be implementing their requirements on different timetables. Less drastic mechanisms than subjecting people living in downwind receptor areas to continuing high levels of air pollution caused in part by upwind-state pollution are available if the actual implementation of mandatory CAA requirements in the downwind areas is delayed: CAA section 304(a)(2) provides for judicial recourse where there is an alleged failure by the Agency to perform a nondiscretionary duty; that recourse is for the Agency to be placed on a court-ordered deadline to address the relevant obligations. *See Oklahoma* v. *U.S. EPA,* 723 F.3d 1201, 1223–24 (10th Cir. 2013); *Montana Sulphur and Chemical Co.* v. *U.S. EPA,* 666 F.3d 1174, 1190–91 (9th Cir. 2012). Commenter focuses on the EPA's evaluation of New York's Good Neighbor SIP submission to argue the EPA is treating upwind and downwind states dissimilarly. The argument conflates New York's role as both a downwind and an upwind state. In evaluating the Good Neighbor SIP submission that New York submitted, the EPA identified as a basis for disapproval that none of the state emissions control programs New York cited included implementation timeframes to achieve the reductions, let alone ensure they were achieved by 2023. 87 FR 9484, 9494 (Feb. 22, 2022). The EPA conducted the same inquiry into other states' claims regarding their existing or proposed state laws or other emissions reductions claimed in their SIP submissions. *See, e.g.,* 87 FR 9472–73 (evaluating claims regarding emissions reductions anticipated under Maryland's state law); 87 FR 9854 (evaluating claims regarding emissions reductions anticipated under Illinois' state law). Consistent with its treatment of the other upwind states included in this action, the EPA in a separate action disapproved New York's good neighbor SIP submission for the 2015 ozone NAAQS because its arguments did not demonstrate that it had fully prohibited emissions significantly contributing to out of state nonattainment or maintenance problems.

Commenter attempts to contrast this evaluation with what it believes is the EPA's permissive attitude toward delays by downwind states, specifically claiming that ''certain nonattainment areas have delayed implementation of nonattainment controls until 2025 and beyond.'' This apparently references New York's simple cycle and regenerative combustion turbines (SCCT) controls, which commenter cited elsewhere in its comments. New York's SCCT controls were not included by New York in its good neighbor SIP submission, nor was the prior approval of the SCCT controls reexamined by the EPA or reopened for consideration by the Agency in this action. Although not part of this rulemaking, the EPA notes that the SCCT controls were approved by the EPA as a SIP strengthening measure and not to satisfy any specific planning requirements for the 2015 ozone NAAQS under CAA section 182. 86 FR 43956, 43958 (Aug. 11, 2021). The SCCT controls submitted to the EPA were already a state rule, and the only effect under the CAA of the EPA approving them into New York's SIP was to make them federally enforceable. 86 FR 43956, 43959 (Aug. 11, 2021). In other words, approval of the SCCT controls did not relieve New York of its nonattainment planning obligations for the 2015 ozone NAAQS.

The EPA notes that the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area was initially designated as Moderate nonattainment. 83 FR 25776 (June 4, 2018). Pursuant to this designation, New York was required to submit a RACT SIP submission and an attainment demonstration no later than 24 months and 36 months, respectively, after the effective date of the Moderate designation. CAA section 182; 40 CFR 51.1308(a), 51.1312(a)(2). New York submitted a RACT SIP for the 2015 ozone standards on January 29, 2021,[128] and the EPA is currently evaluating that submission. New York has not yet submitted its attainment demonstration, which was due August 3, 2021. Further, the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area remains subject to the Moderate nonattainment area date of August 3, 2024. If it fails to attain the 2015 ozone NAAQS by August 3, 2024, it will be reclassified to Serious nonattainment, resulting in additional requirements on the New York nonattainment area.

In any case, regardless of the status of New York's and the EPA's efforts in relation to the New York-Northern New Jersey-Long Island, NY-NJ-CT nonattainment area (which are outside the scope of this action), the EPA's evaluation of 2023 as the relevant analytic year in assessing New York's and other states' good neighbor obligations is consistent with the statutory framework and court decisions calling on the agency to align these obligations with the downwind areas' statutory attainment schedule. The EPA further responds to these comments in the *RTC* document in the docket.

The remainder of this section includes information on (1) the air quality modeling platform used in support of the final rule with a focus on the base year and future year base case emissions inventories, (2) the method for projecting design values in 2023 and 2026, and (3) the approach for calculating ozone contributions from upwind states. The Agency also provides the design values for nonattainment and maintenance receptors and the largest predicted downwind contributions in 2023 and 2026 from each state. The 2016 base period and 2023 and 2026 projected design values and contributions for all ozone monitoring sites are provided in the docket for this rule. The ''Air Quality Modeling Technical Support Document for the Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Final Rulemaking'' (Mar. 2023), hereinafter referred to as the Air Quality Modeling Final Rule TSD, in the docket for this final rule contains more detailed information on the air quality modeling aspects of this rule.

B. Overview of Air Quality Modeling Platform

The EPA used version 3 of the 2016-based modeling platform (*i.e.,* 2016v3) for the air quality modeling for this final rule. This modeling platform includes 2016 base year emissions from anthropogenic and natural sources and anthropogenic emissions projections for 2023 and 2026. The emissions data contained in this platform represent an update to the 2016 version 2 inventories used for the proposal modeling.

The air quality modeling for this final rule was performed for a modeling region (*i.e.,* modeling domain) that covers the contiguous 48 states using a horizontal resolution of 12 x 12 km. The EPA used the CAMx version 7.10 for air quality modeling which is the same model that EPA used for the proposed rule air quality modeling.[129] Additional information on the 2016-based air quality modeling platform can be found in the Air Quality Modeling Final Rule TSD.

Comment: Commenters noted that the 2016 base year summer maximum daily average 8-hour (MDA8) ozone predictions from the proposal modeling were biased low compared to the corresponding measured concentrations in certain locations. In this regard, commenters said that model

[128] *https://edap.epa.gov/public/extensions/S4S_Public_Dashboard_2/S4S_Public_Dashboard_2.html.*

[129] Ramboll Environment and Health, January 2021, *https://www.camx.com.*

performance statistics for a number of monitoring sites, particularly those in portions of the West and in the area around Lake Michigan, were outside the range of published performance criteria for normalized mean bias (NMB) and normalized mean error (NME) of less than ±15 percent and less than 25 percent, respectively (Emory, et al., 2017).[130] The commenters said EPA must investigate the factors contributing to low bias and make necessary corrections to improve model performance in the final rule modeling. Some commenters said that EPA should include NO_X emissions from lightning strikes and assess the treatment of other background sources of ozone to improve model performance for the final rule. Additional information on the comments on model performance can be found in the *RTC* document for this final rule.

Response: In response to these comments EPA examined the temporal and spatial characteristics of model under prediction to investigate the possible causes of under prediction of MDA8 ozone concentrations in different regions of the U.S. in the proposal modeling. EPA's analysis indicates that the under prediction was most extensive during May and June with less bias during July and August in most regions of the U.S. For example, in the Upper Midwest region model under prediction was larger in May and June compared to July through September. Specifically, in the proposal modeling, the normalized mean bias for days with measured concentrations ≥60 ppb improved from a 21.4 percent under prediction for May and June to a 12.6 percent under prediction in the period July through September. As described in the Air Quality Modeling Final Rule TSD, the seasonal pattern in bias in the Upper Midwest region improves somewhat gradually with time from the middle of May to the latter part of June. In view of the seasonal pattern in bias in the Upper Midwest and in other regions of the U.S., EPA focused its investigation of model performance on model inputs that, by their nature, have the largest temporal variation within the ozone season. These inputs include emissions from biogenic sources and lightning NO_X, and contributions from transport of international anthropogenic emissions and natural sources into the U.S. Both biogenic and lightning NO_X emissions in the U.S. dramatically increase from spring to summer.[131] [132] In contrast, ozone transported into the U.S. from international anthropogenic and natural sources peaks during the period March through June, with lower contributions during July through September.[133] [134] To investigate the impacts of these sources, EPA conducted sensitivity model runs which focused on the effects on model performance of adding NO_X emissions from lightning strikes, updating biogenic emissions, and using an alternative approach for quantifying transport of ozone and precursor pollutants into the U.S. from international anthropogenic and natural sources. The development of lightning NO_X emissions and the updates to biogenic emissions, are described in section IV.C of this document. In the proposal modeling the amount of transport from international anthropogenic and natural sources was based on a simulation of the hemispheric version of the Community Multi-scale Air Quality Model (H–CMAQ) for 2016.[135] The outputs from this hemispheric modeling were then used to provide boundary conditions for national scale air quality modeling at proposal.[136] Overall, H–CMAQ tends to under-predict daytime ozone concentrations at rural and remote monitoring sites across the U.S. during the spring of 2016 whereas the predictions from the GEOS-Chem global model [137] were generally less biased.[138] During the summer of 2016 both models showed varying degrees of over prediction with GEOS-Chem showing somewhat greater over-prediction, compared to H–CMAQ. In view of those results, EPA examined the impacts of using GEOS-Chem as an alternative to H–CMAQ for providing boundary conditions for the final rule modeling.

For the lightning NO_X, biogenics, and GEOS-Chem sensitivity runs, EPA reran the proposal modeling using each of these inputs, individually. Results from these sensitivity runs indicate that each of the three updates provides an improvement in model performance. However, by far the greatest improvement in model performance is attributable to the use of GEOS-Chem. In view of these results EPA has included lightning NO_X emissions, updated biogenic emissions, and international transport from GEOS-Chem in the final rule air quality modeling. Details on the results of the individual sensitivity runs can be found in the Air Quality Modeling Final Rule TSD. For the air quality modeling supporting this final action, model performance based on days in 2016 with measured MDA8 ozone ≥60 ppb is considerably improved (*i.e.,* less bias and error) compared to the proposal modeling in nearly all regions of the U.S. For example, in the Upper Midwest, which includes monitoring sites along Lake Michigan, the normalized mean bias improved from a 19 percent under prediction to a 6.9 percent under prediction and in the Southwest region, which includes monitoring sites in Denver and Salt Lake City, normalized mean bias improved from a 13.6 percent under prediction to a 4.8 percent under prediction.[139] In all regions, the

[130] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[131] Guenther, A.B., 1997. Seasonal and spatial variations in natural volatile organic compound emissions. Ecol. Appl. 7, 34–45. *https://doi.org/10.1890/1051-0761(1997)007[0034:SASVIN]2.0.CO;2.* Guenther, A., Hewitt, C.N., Erickson, D., Fall, R.

[132] Kang D, Mathur R, Pouliot GA, Gilliam RC, Wong DC. Significant ground-level ozone attributed to lightning-induced nitrogen oxides during summertime over the Mountain West States. NPJ Clim Atmos Sci. 2020 Jan 30;3:6. doi: 10.1038/s41612–020–0108–2. PMID: 32181370; PMCID: PMC7075249.

[133] Jaffe DA, Cooper OR, Fiore AM, Henderson BH, Tonnesen GS, Russell AG, Henze DK, Langford AO, Lin M, Moore T. Scientific assessment of background ozone over the U.S.: Implications for air quality management. Elementa (Wash DC). 2018;6(1):56. doi: 10.1525/elementa.309. PMID: 30364819; PMCID: PMC6198683.

[134] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, N. Possiel, G. Pouliot, B. Timin, K.W. Appel, 2019. Global Sources of North American Ozone. Presented at the 18th Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 21–23, 2019.

[135] Mathur, R., Gilliam, R., Bullock, O.R., Roselle, S., Pleim, J., Wong, D., Binkowski, F., and 1 Streets, D.: Extending the applicability of the community multiscale air quality model to 2 hemispheric scales: motivation, challenges, and progress. In: Steyn DG, Trini S (eds) Air 3 pollution modeling and its applications, XXI. Springer, Dordrecht, pp 175–179, 2012.

[136] Boundary conditions are the concentrations of pollutants along the north, east, south, and west boundaries of the air quality modeling domain. Boundary conditions vary in space and time and are typically obtained from predictions of global or hemispheric models. Information on how boundary conditions were developed for the final rule modeling can be found in the Air Quality Modeling Final Rule TSD.

[137] I. Bey, D.J. Jacob, R.M. Yantosca, J.A. Logan, B.D. Field, A.M. Fiore, Q. Li, H.Y. Liu, L.J. Mickley, M.G. Schultz. Global modeling of tropospheric chemistry with assimilated meteorology: model description and evaluation. J. Geophys. Res. Atmos., 106 (2001), pp. 23073–23095, 10.1029/2001jd000807.

[138] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, G., N. Possiel, B. Timin, K.W. Appel, 2022. Meteorological and Emission Sensitivity of Hemispheric Ozone and $PM_{2.5}$. Presented at the 21st Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 17–19, 2022.

[139] A comparison of model performance from the proposal modeling to the final modeling for

Continued

normalized mean bias and normalized mean error statistics for high ozone days based on the final rule modeling are within the range of performance criteria benchmarks (*i.e.,* < ±15 percent for normalized mean bias and <25 percent for normalized mean error).[140] Additional information on model performance is provided in the Air Quality Modeling Final Rule TSD. In summary, EPA included emissions of lightning NO_X, as requested by commenters, and investigated and addressed concerns about model performance for the final rule modeling.

C. Emissions Inventories

The EPA developed emissions inventories to support air quality modeling for this final rule, including emissions estimates for EGUs, non-EGU point sources (*i.e.,* stationary point sources), stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, other mobile sources, wildfires, prescribed fires, and biogenic emissions that are not the direct result of human activities. The EPA's air quality modeling relies on this comprehensive set of emissions inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements.

Prior to air quality modeling, the emissions inventories were processed into a format that is appropriate for the air quality model to use. To prepare the emissions inventories for air quality modeling, the EPA processed the emissions inventories using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 4.9 to produce the gridded, hourly, speciated, model-ready emissions for input to the air quality model. Additional information on the development of the emissions inventories and on data sets used during the emissions modeling process are provided in the document titled, ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform'' (Jan. 2023), hereafter known as the 2016v3 Emissions Modeling TSD. This TSD is available in the docket for this rule.[141]

1. Foundation Emissions Inventory Data Sets

The 2016v3 emissions platform is comprised of data from various sources including data developed using models, methods, and source datasets that became available in calendar years 2020 through 2022, in addition to data retained from the Inventory Collaborative 2016 version 1 (2016v1) Emissions Modeling Platform, released in October 2019. The 2016v1 platform was developed through a national collaborative effort between the EPA and state and local agencies along with MJOs. The 2016v2 platform used to support the proposed action included updated data from the 2017 NEI along with updates to models and methods as compared to 2016v1. The 2016v3 platform includes updates to the 2016v2 platform implemented in response to comments along with other updates to the 2016v2 platform such as corrections and the incorporation of updated data sources that became available prior to the 2016v3 inventories being developed. Several commenters noted that the 2016v2 platform did not include NO_X emissions that resulted from lightning strikes. To address this, lightning NO_X emissions were computed and included in the 2016v3 platform.

For this final rule, the EPA developed emissions inventories for the base year of 2016 and the projected years of 2023 and 2026. The 2023 and 2026 inventories represent changes in activity data and of predicted emissions reductions from on-the-books actions, planned emissions control installations, and promulgated Federal measures that affect anthropogenic emissions.[142] The 2016 emissions inventories for the U.S. primarily include data derived from the 2017 National Emissions Inventory (2017 NEI)[143] and data specific to the year of 2016. The following sections provide an overview of the construct of the 2016v3 emissions and projections. The fire emissions were unchanged between the 2016v2 and 2016v3 emissions platforms. For the 2016v3 platform, the biogenic emissions were updated to use the latest available versions of the Biogenic Emissions Inventory System and associated land use data to help address comments related to a degradation in model performance in the 2016v2 platform as compared to the 2016v1 platform. Details on the construction of the inventories are available in the 2016v3 Emissions Modeling TSD. Details on how the EPA responded to comments related to emissions inventories are available in the *RTC* document for this rule.

2. Development of Emissions Inventories for EGUs

a. EGU Emissions Inventories Supporting This Final Rule

Development of emissions inventories for annual NO_X and SO_2 emissions for EGUs in the 2016 base year inventory are based primarily on data from continuous emissions monitoring systems (CEMS) and other monitoring systems allowed for use by qualifying units under 40 CFR part 75, with other EGU pollutants estimated using emissions factors and annual heat input data reported to the EPA. For EGUs not reporting under Part 75, the EPA used data submitted to the NEI by the state, local, and tribal agencies. The Air Emissions Reporting Rule (80 FR 8787; February 19, 2015), requires that Type A point sources large enough to meet or exceed specific thresholds for emissions be reported to the EPA every year, while the smaller Type B point sources must only be reported to EPA every 3 years. Emissions data for EGUs that did not have data submitted to the NEI specific to the year 2016 were filled in with data from the 2017 NEI. For more information on the details of how the 2016 EGU emissions were developed and prepared for air quality modeling, see the 2016v3 Emissions Modeling TSD.

The EPA projected 2023 and 2026 baseline EGU emissions using the version 6—Updated Summer 2021 Reference Case of the Integrated Planning Model (IPM). IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades, including all prior implemented CSAPR rulemakings, to better understand power sector behavior under future business-

individual monitoring sites can be found in the docket for this final rule.

[140] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[141] See 2016v3 Emissions Modeling TSD, also available at *https://www.epa.gov/air-emissions-modeling/2016v3-platform.*

[142] Biogenic emissions and emissions from wildfires and prescribed fires were held constant between 2016 and the future years because (1) these emissions are tied to the 2016 meteorological conditions and (2) the focus of this rule is on the contribution from anthropogenic emissions to projected ozone nonattainment and maintenance.

[143] *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-technical-support-document-tsd.*

as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[144] The EPA relied on the same model platform at final as it did at proposal, but made substantial updates to reflect public comments on near-term fossil fuel market price volatility and updated fleet information reflecting Summer 2022 U.S. Energy Information Agency (EIA) 860 data, unit-level comments, and additional updates to the National Electric Energy Data System (NEEDS) inventory.

The IPM version 6—Updated Summer 2021 Reference Case incorporated recent updates through the Summer of 2022 to account for updated Federal and state environmental regulations (including Renewable Portfolio Standards (RPS), Clean Energy Standards (CES) and other state mandates), fleet changes (committed EGU retirements and new builds), electricity demand, technology cost and performance assumptions from recent data (for renewables adopting from National Renewable Energy Lab (NREL's) Annual Technology Baseline 2020 and for fossil sources from EIA's Annual Energy Outlook (AEO) 2020. Natural gas and coal price projections reflect data developed in Fall 2020 but updated in summer of 2022 to capture near-term price volatility and current market conditions. The inventory of EGUs provided as an input to the model was the NEEDS fall 2022 version and is available on EPA's website.[145] This version of NEEDS reflects announced retirements and under-construction new builds known as of early summer 2022. This projected base case accounts for the effects of the finalized Mercury and Air Toxics Standards rule, CSAPR, the CSAPR Update, the Revised CSAPR Update, NSR enforcement settlements, the final ELG Rule, CCR Rule, and other on-the-books Federal and state rules (including renewable energy tax credit extensions from the Consolidated Appropriations Act of 2021) through early 2021 impacting SO_2, NO_X, directly emitted particulate matter, CO_2, and power plant operations. It also includes final actions the EPA has taken to implement the Regional Haze Rule and best available retrofit technology (BART) requirements. Documentation of IPM version 6 and NEEDS, along with updates, is in Docket ID No. EPA–HQ–OAR–2021–0668 and available online at *https://www.epa.gov/airmarkets/power-sector-modeling*. IPM has projected output years for 2023 and 2025. IPM year 2025 outputs were adjusted for known retirements to be reflective of year 2026, and IPM year 2030 outputs were used for the year 2032 as is specified by the mapping of IPM output years to specific years.

Additional 2023 through 2026 EGU emissions baseline levels were developed through engineering analytics as an alternative approach that did not involve IPM. The EPA developed this inventory for use in Step 3 of this final rule, where it determines emissions reduction potential and corresponding state-level emissions budgets. IPM includes optimization and perfect foresight in solving for least cost dispatch. Given that this final rule will likely become effective immediately prior to the start of the 2023 ozone season, the EPA adopted a similar approach to the CSAPR Update and the Revised CSAPR Update where it utilized historical data and an engineering analytics approach in Step 3 to avoid overstating optimization and dispatch decisions in state-emissions budget quantification that may not be possible in a short time frame. The EPA does this by starting with unit-level reported data and only making adjustments to reflect known baseline changes such as planned retirements and new builds (for the base case scenarios) and also identified mitigation strategies for determining state emissions budgets. In both the CSAPR Update and in this rule at Step 3, the EPA complemented that projected IPM EGU outlook with an historical (*e.g.,* engineering analytics) perspective based on historical data that only factors in known changes to the fleet. This 2023 engineering analytics data set is described in more detail in the Ozone Transport Policy Analysis Final Rule TSD and corresponding Appendix A: State Emissions Budgets Calculations and Underlying Data. The Engineering Analysis used in Step 3 is also discussed further in section VII.B of this document.

Both IPM and the Engineering Analytics tools are valuable for estimating future EGU emissions and examining the cone of uncertainty around any future sector-level inventory estimate. A key difference between the two tools is that IPM reflects both announced and projected changes in fleet operation, whereas the Engineering Analytics tool only reflects announced changes. By not including projected regional changes that are anticipated in response to market forces and fleet trends, the Engineering Analysis deliberately creates future estimates of the power sector where state estimates are limited to known changes. Throughout all of the CSAPR rules to date, and prior interstate transport actions, the EPA has used IPM at Steps 1 and 2 as it is best suited for projecting emissions in an airshed, at projecting emissions for time horizons more than a few years out (for which changes would not yet be announced and thus projecting changes is critical), and for scenarios where the assumed change in emissions is not being codified into a state emissions reduction requirement. Using IPM at Steps 1 and 2 helps the EPA avoid overstating the current analytic year receptor values (Step 1) and future year linkages (Step 2) by reflecting reductions anticipated to occur within the airshed in the relevant timeframe.

Engineering analytics has been a useful tool for Step 3 state-level emissions reduction estimates in CSAPR rulemaking, because at that step the EPA is dealing with more geographic granularity (state-level as opposed to regional air shed), more near-term (as opposed to medium-term) assessments, and scenarios where reduction estimates are codified into regulatory requirements. Using the Engineering Analytics tool at this step ensures that the EPA is not codifying into the base case, and consequently into state emissions budgets, changes in the power sector that are merely modeled to occur rather than announced by real-world actors.

Finally, both in the Revised CSAPR Update and in this rule, the EPA was able to use the Air Quality Assessment Tool to determine that regardless of which EGU inventory is used, the 2023 geography of the program is not impacted. In other words, regardless of whether a stakeholder takes a more comprehensive view of the EGU future (IPM) or one limited to current data and known changes (Engineering Analysis), the states that are linked to receptors at Steps 1 and 2 would be the same. This finding is consistent with the observation that EGUs are now less than

[144] Detailed information and documentation of EPA's Base Case, including all the underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: *https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-summer-2021-reference-case.*

[145] Available at *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

10 percent of the total ozone-season NO_X inventory and the degree of near-term difference between the IPM and Engineering Analytic regional projections is relatively small on the regional level. The EPA continues to believe that IPM is best suited for Step 1 and Step 2, and engineering analytics is best suited for Step 3 efforts in this rulemaking. The Ozone Transport Policy Analysis Final Rule TSD contains data on 2023 and 2026 AQ impacts of each dataset.

Comment: Some commenters express concern that using IPM for Step 1 and Step 2 captures generation shifting across state lines, which exceeds the EPA's authority. Moreover, the commenters suggest that the resulting proposed baseline EGU inventory may understate emissions levels as it projects economic retirements that are not yet announced or firm. Other commenters more generally allege that the EPA is using different modeling tools at different steps in its analysis, and this introduces confusion or uncertainty into the basis for the EPA's regulatory conclusions.

Response: The EPA believes the first aspect of this comment, in regards to its focus on generation shifting, is misguided in several ways. For Step 1 and Step 2, the EPA models no incremental generation shifting attributable to the implementation of an emissions control policy at Step 3. Rather, any generation patterns are merely a reflection of the model's projection of how regional load requirements will be met with the generation sources serving that region in the baseline. The EPA is not modeling any additional generation shifting, but merely capturing the expected generation dispatch under anticipated baseline market conditions. Electricity generated in one state regularly is transmitted across state boundaries and is used to serve load in other states; IPM is not incentivizing or requiring any additional generation transfer across state lines in this scenario but is merely projecting the pattern of this behavior in the future. Moreover, as noted previously, the EPA affirms its geographic findings at Step 2 (states contributing over 1 percent of the NAAQS to a downwind receptor) using historical data (engineering analysis) in a sensitivity analysis. These historical data reflect the actual generation patterns observed to meet regional load. Therefore, any suggestion by the commenter that the EPA's projected view of baseline grid dispatch is unreasonable, is mooted by the fact that the use of historical reported generation patterns produces the same result. Additionally, at the time of the proposal's analysis, the 2023 ozone season was still nearly two years away. Therefore, it was appropriate for EPA's modeling to project economic retirements as those retirements—which are regularly occurring—are often not firm or announced two years in advance. However, for this final rule, the 2023 analytic year was close enough to the period in which EPA was conducting its analysis that such retirements would likely be announced. Therefore, the EPA was able to incorporate those announced and firm retirements to occur in the 2023 year. Further, in recognition of this very near timeframe, we deactivated IPM's ability to project additional economic retirements for the 2023 year (reflecting the notion that any retirements occurring by 2023 would be known at this point). This adjustment further accommodates the commenters' concern that the baseline overstates generation shifting (driven by retirements) in the near term, and consequently understates emissions levels. Finally, with respect to comments that the EPA is using different modeling tools at different steps in the framework, we previously explained why these techniques are appropriate for the purposes at each step of the analysis, and they are not incompatible nor do they produce results so different as to call into question their reliability or the bases for our regulatory determinations (EPA notes that the nationwide projected ozone season total NO_X emissions vary by less than 1 percent in the 2023 analytic year). Nonetheless, we also observe that the effect of using engineering analytics to inform analysis at Steps 1 and 2 would tend to produce higher assumed emissions from EGUs in the baseline than IPM would project in 2026 and beyond and therefore only strengthen and further affirm the Step 1 and Step 2 geographic findings. EPA's use of different tools to project EGU scenarios is not inconsistent, but rather it is carefully explained as a deliberate measure taken to preserve—not introduce—consistency across each of the Steps in the 4-step framework. By using IPM at Step 1 and 2, EPA is selecting the more conservative approach for identifying the degree of nonattainment and geography of states contributing above 1 percent. By using Engineering Analytics at Step 3, EPA is selecting the more conservative value to codify into state-level budgets.

b. Impact of the Inflation Reduction Act on EGU Emissions

The EGU modeling used to construct the EGU emissions inventories used to inform the modeling projections for 2023 and 2026 was conducted prior to the passage of the Inflation Reduction Act (IRA), Public Law 117–169. The EPA did not have time to incorporate updated EGU projections reflecting the passage of the IRA into the primary air quality modeling for this final rule. However, the EPA was able to perform a sensitivity analysis reflecting the IRA in its EGU NO_X emissions inventories. The results from this scenario were run through AQAT and demonstrated that the status of states identified as linked at the 1 percent of NAAQS contribution threshold (based on the modeling and air quality analysis described in this section) would not change regardless of which inventory (with or without IRA) is used. This sensitivity analysis is presented in the Regulatory Impact Analysis accompanying this rule, and that discussion provides additional detail on the emissions consequences of including the IRA in a baseline EGU inventory. The air quality impact of including the IRA in EPA's emissions inventories and in its Step 3 scenarios is discussed in Appendix K of the Ozone Transport Policy Analysis Final Rule TSD.

The results of this analysis are not surprising and accord with what is generally understood to be the overall effect of the IRA over the short to long term. While the IRA is anticipated to have a potentially dramatic effect on reducing both GHG and conventional pollutant emissions from the power sector, it is likely to have a more substantial impact later in the forecast period (*i.e.,* beyond the attainment deadlines by which the emissions reductions under this final rule must occur). This timing reflects a realistic assessment of utilities', regulators', and transmission authorities' planning requirements associated with the addition of substantial new renewable and storage capacity to the grid, as well as the time needed to integrate that capacity and retire existing capacity. Additionally, the IRA incentives span a longer time period (for example, certain tax incentives for clean energy sources are available until the later of 2032 or the year in which power sector emissions are 75 percent below 2022 levels) and therefore there is no IRA-related deadline to build cleaner generation by 2026. Recent analysis by the Congressional Budget Office supports the finding that the majority of power sector EGU emissions reductions expected from the IRA occur well after the 2023 and 2026 analytic years relevant to the attainment dates and this rulemaking.[146] While the report focuses on CO_2 rather than NO_X, the drivers of the emissions reductions (primarily increased zero-emitting generation) would generally have a downward impact on both pollutants.

We note that important uncertainties remain at this time in the implementation of the IRA that further counsel against over-assuming short-term emissions reductions for purposes of this rule. The legislation provides economic incentives for shifting to cleaner forms of power generation but does not mandate emissions reductions through an enforceable regulatory program. The strength of those incentives will vary to some extent depending on other key market factors (such as the cost of natural gas or renewable energy technologies). Further, some incentives, such as tax credits for carbon capture and storage, could lead EGUs to remain in operation longer, which could in turn result in greater NO_X emissions, if those emissions are not also well controlled.

Nonetheless, while we find that the passage of the IRA does not affect the geography of the rule in terms of which states we identify as linked, the Agency is confident that the incentives toward clean technology provided in the IRA will, in the longer run beyond the 2015 ozone NAAQS attainment deadlines, facilitate ongoing EGU compliance with the emissions reduction requirements of this rule and will reduce costs borne by EGUs and their customers as the U.S. power sector transitions. As discussed in greater detail in section VI.B of this document, we have made several adjustments in the final rule to provide greater flexibility to EGU owners and operators to integrate this rule's requirements with and facilitate the accelerating transition to an overall cleaner electricity-generating sector, which the IRA represents. Despite the uncertainties inherent in the implementation of the IRA at this time, the EPA also has performed a sensitivity analysis on the final rule to confirm that our finding of no overcontrol is robust to a future with the IRA in effect.

3. Development of Emissions Inventories for Stationary Industrial Point Sources

Non-EGU point source emissions are mostly consistent with those in the proposal modeling except where they were updated in response to comments. Several commenters mentioned that point source emissions carried forward from 2014 NEI were not the best estimates of 2017 emissions. Thus, emissions sources in 2016v2 that had been projected from the 2014 NEI in the proposal were replaced with emissions based on the 2017 NEI. Point source emissions submitted to the 2016 NEI or to the 2016v1 platform development process specifically for the year 2016 were retained in 2016v3. Other 2016 non-EGU updates in 2016v3 include a few sources being moved to the EGU inventory, the addition of some control efficiency information for the year 2016, the replacement of most emissions projected from 2014 NEI with data from 2017 NEI, and the inclusion of point source data for solvent processes that had not been included in the 2016v2 non-EGU inventory.

The 2023 and 2026 non-EGU point source emissions were grown from 2016 to those years using factors based on the AEO 2022 and reflect emissions reductions due to known national and local rules, control programs, plant closures, consent decrees, and settlements that could be computed as reductions to specific units by July 2022.

Aircraft emissions and ground support equipment at airports are represented as point sources and are based on adjustments to emissions in the January 2021 version of the 2017 NEI. The EPA developed and applied factors to adjust the 2017 airport emissions to 2016, 2023 and 2026 based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast 2021[147] data, the latest available version at the time the factors were developed. By basing the factors on the latest available Terminal Area Forecast that was released following the most significant pandemic impacts on the aviation sector, the reduction and rebound impacts of the pandemic on aircraft and ground support equipment were reflected in the 2023 and 2026 airport emissions.

Emissions at rail yards were represented as point sources. The 2016 rail yard emissions are largely consistent with the 2017 NEI rail yard emissions. The 2016 and 2023 rail yard emissions were developed through the 2016v1 Inventory Collaborative process, with the 2026 emissions interpolated between the 2023 and 2028 emissions from 2016v1 rail yard emissions were interpolated from the 2016 and 2023 emissions. Class I rail yard emissions were projected based on the AEO freight rail energy use growth rate projections for 2023, and 2026 with the fleet mix assumed to be constant throughout the period.

The EPA made multiple updates to point source oil and gas emissions in response to comments. For the final rule, the point source oil and gas emissions for 2016 were based on the 2016v2 point inventory except that most 2014 NEI-based emissions were replaced with 2017 NEI emissions. Additionally, in response to comments, state-provided emissions equivalent to those in the 2016v1 platform were used for Colorado, and some New Mexico emissions were replaced with data backcast from 2020 to 2016. To develop inventories for 2023 and 2026 for the final rule, the year 2016 oil and gas point source inventories were first projected to 2021 values based on actual historical production data, then those 2021 emissions were projected to 2023 and 2026 using regional projection factors based on AEO 2022 projections. This was an update from the proposal approach that used actual data only through the year 2019, because 2021 data were not yet available. NO_X and VOC reductions resulting from co-benefits of NSPS for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected, along with Natural Gas Turbine and Process Heater NSPS NO_X controls and Oil and Gas NSPS VOC controls. In some cases, year 2019 point source inventory data were used instead of the projected future year emissions except for the Western Regional Air Partnership (WRAP) states of Colorado, New Mexico, Montana, Wyoming, Utah, North Dakota, and South Dakota. The WRAP future year inventory[148] was used in these WRAP states in all future years except in New Mexico where the WRAP base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative code 20.2.50[149] were also included.

4. Development of Emissions Inventories for Onroad Mobile Sources

Onroad mobile sources include exhaust, evaporative, and brake and tire wear emissions from vehicles that drive on roads, parked vehicles, and vehicle refueling. Emissions from vehicles using regular gasoline, high ethanol gasoline, diesel fuel, and electric vehicles were represented, along with buses that used compressed natural gas. The EPA

[146] ''Emissions of Carbon Dioxide In the Electric Power Sector,'' Congressional Budget Office. December 2022. Available at *https://www.cbo.gov/publication/58860*.

[147] *https://www.faa.gov/data_research/aviation/taf/*.

[148] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf*.

[149] *https://www.srca.nm.gov/parts/title20/20.002.0050.html*.

developed the onroad mobile source emissions for states other than California using the EPA's Motor Vehicle Emissions Simulator (MOVES). MOVES3 was released in November 2020 and has been followed by some minor releases that improved the usage of the model but that do not have substantive impacts on the emissions estimates. For the proposal, MOVES3 was run using inputs provided by state and local agencies through the 2017 NEI where available, in combination with nationally available data sets to develop a complete inventory. Onroad emissions were developed based on emissions factors output from MOVES3 runs for the year 2016, coupled with activity data (*e.g.,* vehicle miles traveled and vehicle populations) representing the year 2016. The 2016 activity data were provided by some state and local agencies through the 2016v1 process, and the remaining activity data were derived from those used to develop the 2017 NEI. The onroad emissions were computed within SMOKE by multiplying emissions factors developed using MOVES with the appropriate activity data. Prior to computing the final rule emissions, updates to some onroad inputs were made in response to comments and to implement corrections. Onroad mobile source emissions for California were consistent with the updated emissions data provided by the state for the final rule.

The 2023 and 2026 onroad emissions reflect projected changes to fuel properties and usage, along with the impact of the rules included in MOVES3 for each of those years. MOVES emissions factors for the years 2023 and 2026 were used. A comprehensive list of control programs included for onroad mobile sources is available in the 2016v3 Emissions Modeling TSD. Year 2023 and 2026 activity data for onroad mobile sources were provided by some state and local agencies, and otherwise were projected to 2023 and 2026 by first projecting the 2016 activity to year 2019 based on county level vehicle miles traveled (VMT) from the Federal Highway Administration. Because VMT for onroad mobile sources were substantially impacted by the pandemic and took about two years to rebound to pre-pandemic levels, in the 2016v3 platform no growth in VMT was implemented from 2019 to. The estimated 2021 VMT were then grown from 2021 to 2023 and 2026 using AEO 2022-based factors. Recent updates to inspection and maintenance programs in North Carolina and Tennessee were reflected in the MOVES inputs for the final rule modeling. The 2023 and 2026 onroad mobile emissions were computed within SMOKE by multiplying the respective emissions factors developed using MOVES with the year-specific activity data. Prior to computing the final rule emissions for 2023, the EPA made updates to some onroad inputs in response to comments and to implement corrections.

5. Development of Emissions Inventories for Commercial Marine Vessels

The commercial marine vessel (CMV) emissions in the 2016 base case emissions inventory for this rule were based on those in the 2017 NEI. Factors were applied to adjust the 2017 NEI emissions backward to represent emissions for the year 2016. The CMV emissions reflect reductions associated with the Emissions Control Area proposal to the International Maritime Organization control strategy (EPA–420–F–10–041, August 2010); reductions of NO_X, VOC, and CO emissions for new category 3 (C3) engines that went into effect in 2011; and fuel sulfur limits that went into effect prior to 2016. The cumulative impacts of these rules through 2023 and 2026 were incorporated into the projected emissions for CMV sources. The CMV emissions were split into emissions inventories from the larger C3 engines, and those from the smaller category 1 and 2 (C1C2) engines. CMV emissions in California are based on emissions provided by the state. The CMV emissions are consistent with the emissions for the 2016v1 platform updated CMV emissions released by February 2020 although they include projected emissions for the years of 2023 and 2026 instead of 2023 and 2028. In addition, in response to comments, the EPA implemented an improved process for spatial allocating CMV emissions along state and county boundaries.

6. Development of Emissions Inventories for Other Nonroad Mobile Sources

The EPA developed nonroad mobile source emissions inventories (other than CMV, locomotive, and aircraft emissions) for 2016, 2023, and 2026 from monthly, county, and process level emissions output from MOVES3. Types of nonroad equipment include recreational vehicles, pleasure craft, and construction, agricultural, mining, and lawn and garden equipment. State-submitted emissions data for nonroad sources were used for California. The nonroad emissions for the final rule were unchanged from those at the proposal. The nonroad mobile emissions control programs include reductions to locomotives, diesel engines, and recreational marine engines, along with standards for fuel sulfur content and evaporative emissions. A comprehensive list of control programs included for mobile sources is available in the 2016v3 Emissions Modeling TSD.

Line haul locomotives are also considered a type of nonroad mobile source but the emissions inventories for locomotives were not developed using MOVES3. Year 2016 locomotive emissions were developed through the 2016v1 collaborative process and the year 2016 emissions are mostly consistent with those in the 2017 NEI. More information on the development of the Class I, Class II and III, and commuter rail line haul locomotive emissions is available in the 2016v3 Emissions Modeling TSD. The projected locomotive emissions for 2023 and 2026 were developed by applying factors to the 2016 emissions using activity data based on AEO freight rail energy use growth rate projections along with emissions rates adjusted to account for recent historical trends. The emission factors used for NO_X, PM10 and VOC for line haul locomotives in the analytic years were derived from trend lines based on historic line-haul emission factors from the period of 2007 through 2017 and extrapolated to 2023 and 2026.

7. Development of Emissions Inventories for Nonpoint Sources

For stationary nonpoint sources, some emissions in the 2016 base case emissions inventory come directly from the 2017 NEI, others were adjusted from the 2017 NEI to represent 2016 levels, and the remaining emissions including those from oil and gas, fertilizer, and solvents were computed specifically to represent 2016. Stationary nonpoint sources include evaporative sources, consumer products, fuel combustion that is not captured by point sources, agricultural livestock, agricultural fertilizer, residential wood combustion, fugitive dust, and oil and gas sources. The emissions sources derived from the 2017 NEI include agricultural livestock, fugitive dust, residential wood combustion, waste disposal (including composting), bulk gasoline terminals, and miscellaneous non-industrial sources such as cremation, hospitals, lamp breakage, and automotive repair shops. A recent method to compute solvent VOC emissions was used.[150]

Where comments were provided about projected control measures or

[150] *https://doi.org/10.5194/acp-21-5079-2021.*

changes in nonpoint source emissions, those inputs were first reviewed by the EPA. Those found to be based on reasonable data for affected emissions sources were incorporated into the projected inventories for 2023 and 2026 to the extent possible. Where possible, projection factors based on the AEO used data from AEO 2022, the most recent AEO at the time available at the time the inventories were developed. Federal regulations that impact the nonpoint sources were reflected in the inventories. Adjustments for state fuel sulfur content rules for fuel oil in the Northeast were included along with solvent controls applicable within the ozone transport region. Details are available in the 2016v3 Emissions Modeling TSD.

Nonpoint oil and gas emissions inventories for many states were developed based on outputs from the 2017 NEI version of the EPA Oil and Gas Tool using activity data for year 2016. Production-related emissions data from the 2017 NEI were used for Oklahoma, 2016v1 emissions were used for Colorado and for Texas production-related sources to response to comments. Data for production-related nonpoint oil and gas emissions in the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming were obtained from the WRAP baseline inventory.[151] A California Air Resources Board-provided inventory was used for 2016 oil and gas emissions in California. Nonpoint oil and gas inventories for 2023 and 2026 were developed by first projecting the 2016 oil and gas inventories to 2021 values based on actual production data. Next, those 2021 emissions were projected to 2023 and 2026 using regional projection factors by product type based on AEO 2022 projections. A 2017–2019 average inventory was used for oil and natural gas exploration emissions in 2023 and 2026 except for California and in the WRAP states in which data from the WRAP future year inventory [152] were used. NO_X and VOC reductions that are co-benefits to the NSPS for RICE are reflected, along with Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls. The WRAP future year inventory was used for oil and natural gas production sources in 2023 and 2026 except in New Mexico where the WRAP Base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative Code 20.2.50 were included.

D. Air Quality Modeling To Identify Nonattainment and Maintenance Receptors

In this section, the Agency describes the air quality modeling and analyses performed in Step 1 to identify locations where the Agency expects there to be nonattainment or maintenance receptors for the 2015 ozone NAAQS in the 2023 and 2026 analytic years. Where the EPA's analysis shows that an area or site does not fall under the definition of a nonattainment or maintenance receptor in these analytic years, that site is excluded from further analysis under this rule.

In the proposed rule, the EPA applied the same approach used in the CSAPR Update and the Revised CSAPR Update to identify nonattainment and maintenance receptors for the 2008 ozone NAAQS.[153] *See* 86 FR 23078–79. The EPA's approach gives independent effect to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina.*[154] Further, in its decision on the remand of the CSAPR from the Supreme Court in the *EME Homer City* case, the D.C. Circuit confirmed that EPA's approach to identifying maintenance receptors in the CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision. *EME Homer City II,* 795 F.3d at 136.

In the CSAPR Update and the Revised CSAPR Update, the EPA identified nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the NO_X SIP Call and CAIR, where the EPA defined nonattainment receptors as those areas that both currently monitor nonattainment and that the EPA projects will be in nonattainment in the future compliance year.[155]

The Agency explained in the NO_X SIP Call and CAIR and then reaffirmed in the CSAPR Update that the EPA has the most confidence in our projections of nonattainment for those monitoring sites that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those monitoring sites that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that site. The variability in air quality was determined by evaluating the ''maximum'' future design value at each monitoring site based on a projection of the maximum measured design value over the relevant period. The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, and air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur.[156] The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

Therefore, applying this methodology in this rule, the EPA assessed the magnitude of the projected maximum design values for 2023 and 2026 at each monitoring site in relation to the 2015 ozone NAAQS and, where such a value exceeds the NAAQS, the EPA determined that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City II.*[157] That is,

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[151] *http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf.*

[152] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[153] *See* 86 FR 23078–79.

[154] 531 F.3d at 910–911 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[155] *See* 63 FR 57375, 57377 (October 27, 1998); 70 FR 25241 (January 14, 2005). *See also North Carolina,* 531 F.3d at 913–914 (affirming as reasonable EPA's approach to defining nonattainment in CAIR).

[156] The EPA's air quality modeling guidance identifies the use of the highest of the relevant base period design values as a means to evaluate future year attainment under meteorological conditions that are especially conducive to ozone formation. *See* U.S. Environmental Protection Agency, 2018. Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, Research Triangle Park, NC.

[157] *See* 795 F.3d at 136.

monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.[158]

Recognizing that nonattainment receptors are also, by definition, maintenance receptors, the EPA often uses the term ''maintenance-only'' to refer to receptors that are not also nonattainment receptors. Consistent with the concepts for maintenance receptors, as described previously, the EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values. In addition, those monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance only'' receptors, even if they are currently measuring nonattainment based on the most recent official design values.[159]

Comment: The EPA received comments claiming that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on the EPA's modeling for the proposed action are currently measuring nonattainment based on data from 2020 and 2021. One commenter requested that the EPA determine whether its past modeling tends to overestimate or underestimated actual observed design values. If EPA finds that the agency's model tends to underestimate future year design values, the commenter requests that EPA re-run its ozone modeling, incorporating parameters that account for this tendency.

Response: In response to comments, the EPA compared the projected 2023 design values based on the proposal modeling to recent trends in measured data. As a result of this analysis, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* sites that are not modeling-based receptors). It would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has also developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites.

Specifically, the EPA has identified monitoring sites with measured 2021 and preliminary 2022 design values *and* 4th high maximum daily 8-hour average (MDA8) ozone in both 2021 and 2022 (preliminary data) that exceed the NAAQS, although projected to be in attainment in 2023, as having the greatest risk of continuing to have a problem attaining the standard in 2023. These criteria sufficiently consider measured air quality data so as to avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. Moreover, 2023 is so near in time that recent measured ozone levels can be used to reasonably project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action, while also identifying all transport receptors.

For purposes of this action, we treat these violating monitors as an additional type of maintenance-only receptor. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment such that they should be considered nonattainment receptors. Rather, our authority for treating these sites as receptors in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523.

We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Despite the implications of the current measured data suggesting there will be a nonattainment problem at these sites in 2023, we cannot definitively establish that such sites will be in nonattainment in 2023 in light of our modeling projections. In the face of this uncertainty, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if an area may be technically in attainment, we have reliable information indicating that there is an identified risk that attainment will not in fact be achieved.

[158] The EPA issued a memorandum in October 2018, providing additional information to states developing interstate transport SIP submissions for the 2015 8-hour ozone NAAQS concerning considerations for identifying downwind areas that may have problems maintaining the standard at Step 1 of the 4-step interstate transport framework. *See* Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0668 or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.* EPA is not applying the suggested analytical approaches in that memorandum in this rule, nor would those approaches be appropriate in light of currently available data. Potential alternative approaches would introduce unnecessary and substantial additional analytical burdens that could frustrate timely and efficient implementation of good neighbor obligations. In addition, the information supplied in that memorandum is now outdated due to several additional years of air quality monitoring data and updated modeling results. EPA's current approach to defining ''maintenance'' receptors has been upheld and continues to provide an appropriate approach to addressing the ''interference with maintenance'' prong of the Good Neighbor provision. *See EME Homer City,* 795 F.3d 118, 136–37; *Wisconsin,* 938 F.3d at 325–26.

[159] See *https://www.epa.gov/air-trends/air-quality-design-values* for design value reports. At the time of this action, the most recent reports available are for the calendar year 2021.

However, because we did not identify this basis for receptor-identification at proposal, in this final action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring taking final action on that state's SIP submittal. This is the case for the State of Tennessee. Among the states that previously had their transport SIPs fully approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good neighbor obligations as expeditiously as practicable in a future action.

E. Methodology for Projecting Future Year Ozone Design Values

Consistent with the EPA's modeling guidance, the 2016 base year and future year air quality modeling results were used in a relative sense to project design values for 2023 and 2026. That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values [160] up or down depending on the relative (percent) change in model predictions for each location. The modeling guidance recommends using measured ozone concentrations for the 5-year period centered on the base year as the air quality data starting point for future year projections. This average design value is used to dampen the effects of inter-annual variability in meteorology on ozone concentrations and to provide a reasonable projection of future air quality at the receptor under average conditions. In addition, the Agency calculated maximum design values from within the 5-year base period to represent conditions when meteorology is more favorable than average for ozone formation. Because the base year for the air quality modeling used in this final rule is 2016, measured data for 2014–2018 (*i.e.,* design values for 2016, 2017, and 2018) were used to project average and maximum design values in 2023 and 2026.

The ozone predictions from the 2016 and future year air quality model simulations were used to project 2016–2018 average and maximum ozone design values to 2023 and 2026 using an approach similar to the approach in EPA's guidance for attainment demonstration modeling. This guidance recommends using model predictions from the 3 x 3 array of grid cells [161] surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site.[162] However, the guidance also notes that an alternative array of grid cells may be used in certain situations where local topographic or geographical feature (*e.g.,* a large water body or a significant elevation change) may influence model response.

The 2016–2018 base period average and maximum design values were multiplied by the RRF to project each of these design values to each of the three future years. In this manner, the projected design values are grounded in monitored data, and not the absolute model-predicted future year concentrations. Following the approach in the CSAPR Update and the Revised CSAPR Update, the EPA also projected future year design values based on a modified version of the ''3 × 3'' approach for those monitoring sites located in coastal areas. In this alternative approach, the EPA eliminated from the RRF calculations the modeling data in those grid cells that are dominated by water (*i.e.,* more than 50 percent of the area in the grid cell is water) and that do not contain a monitoring site (*i.e.,* if a grid cell is more than 50 percent water but contains an air quality monitor, that cell would remain in the calculation). The choice of more than 50 percent of the grid cell area as water as the criteria for identifying overwater grid cells is based on the treatment of land use in the Weather Research and Forecasting model (WRF).[163] Specifically, in the WRF meteorological model those grid cells that are greater than 50 percent overwater are treated as being 100 percent overwater. In such cases the meteorological conditions in the entire grid cell reflect the vertical mixing and winds over water, even if part of the grid cell also happens to be over land with land-based emissions, as can often be the case for coastal areas. Overlaying land-based emissions with overwater meteorology may be representative of conditions at coastal monitors during times of on-shore flow associated with synoptic conditions or sea-breeze or lake-breeze wind flows. But there may be other times, particularly with off-shore wind flow, when vertical mixing of land-based emissions may be too limited due to the presence of overwater meteorology. Thus, for our modeling the EPA projected average and maximum design values at individual monitoring sites based on both the ''3 × 3'' approach as well as the alternative approach that eliminates overwater cells in the RRF calculation for near-coastal areas (*i.e.,* ''no water'' approach). The projected 2023 and 2026 design values using both the ''3 × 3'' and ''no-water'' approaches are provided in the docket for this final rule. For this final rule, the EPA is relying upon design values based on the ''no water'' approach for identifying nonattainment and maintenance receptors.[164]

Consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS, the projected design values are truncated to integers in units of ppb.[165] Therefore, projected design values that are greater than or equal to 71 ppb are considered to be violating the 2015 ozone NAAQS. For those sites that are projected to be violating the NAAQS based on the average design values in the future analytic years, the Agency examined the measured design values for 2021, which are the most recent official measured design values at the time of this final rule. As noted earlier, the Agency is identifying nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current

[160] The ozone design value at a particular monitoring site is the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration at that site.

[161] As noted in this section, each model grid cell is 12 x 12 km.

[162] The relative response factor represents the change in ozone at a given site. To calculate the RRF, the EPA's modeling guidance recommends selecting the 10 highest ozone days in an ozone season at a given monitor in the base year, noting which of the grid cells surrounding the monitor experienced the highest ozone concentrations in the base year, and averaging those ten highest concentrations. The model is then run using the projected year emissions, in this case 2023, with all other model variables held constant. Ozone concentrations from the same ten days, in the same grid cells, are then averaged. The fractional change between the base year (2016 model run) average ozone concentration and the future year (*e.g.,* 2023 model run) average ozone concentration represents the relative response factor.

[163] *https://www.mmm.ucar.edu/weather-research-and-forecasting-model.*

[164] Using design values from the ''3 × 3'' approach, the maintenance-only receptor at site 550590019 in Kenosha County, WI would become a nonattainment receptor because the average design value with the ''3 × 3'' approach is 72.0 ppb versus 70.8 ppb with the ''no water'' approach. In addition, the maintenance-only receptor at site 090099002 in New Haven County, CT would become a nonattainment receptor using the ''3 × 3'' approach because the average design value with the ''3 × 3'' approach is 71.2 ppb versus 70.5 ppb with the ''no water'' approach.

[165] 40 CFR part 50, appendix P—Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone.

measured air quality and also have projected average design values of 71 ppb or greater. Maintenance-only receptors include both (1) those sites with projected average design values above the NAAQS that are currently measuring clean data (*i.e.,* ozone design values below the level of the 2015 ozone NAAQS) and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 71 ppb or greater. In addition to the maintenance-only receptors, ozone nonattainment receptors are also maintenance receptors because the maximum design values for each of these sites is always greater than or equal to the average design value. The monitoring sites that the Agency projects to be nonattainment and maintenance receptors for the ozone NAAQS in the 2023 and 2026 base case are used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of the 2015 ozone NAAQS as part of this final rule.[166]

Table IV.D–1 contains the 2016-centered [167] base period average and maximum 8-hour ozone design values, the 2023 base case average and maximum design values and the measured 2021 design values for the sites that are projected to be nonattainment receptors in 2023. Table IV.D–2 contains this same information for monitoring sites that are projected to be maintenance-only receptors in 2023. The design values for all monitoring sites in the U.S. are provided in the docket for this rule. Additional details on the approach for projecting average and maximum design values are provided in the Air Quality Modeling Final Rule TSD.

TABLE IV.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS

Monitor ID	State	County	2016 Centered average	2016 Centered maximum	2023 Average	2023 Maximum	2021
060650016	CA	Riverside	79.0	80.0	72.2	73.1	78
060651016	CA	Riverside	99.7	101.0	91.0	92.2	95
080350004	CO	Douglas	77.3	78	71.3	71.9	83
080590006	CO	Jefferson	77.3	78	72.8	73.5	81
080590011	CO	Jefferson	79.3	80	73.5	74.1	83
090010017	CT	Fairfield	79.3	80	71.6	72.2	79
090013007	CT	Fairfield	82.0	83	72.9	73.8	81
090019003	CT	Fairfield	82.7	83	73.3	73.6	80
481671034	TX	Galveston	75.7	77	71.5	72.8	72
482010024	TX	Harris	79.3	81	75.1	76.7	74
490110004	UT	Davis	75.7	78	72.0	74.2	78
490353006	UT	Salt Lake	76.3	78	72.6	74.2	76
490353013	UT	Salt Lake	76.5	77	73.3	73.8	76
551170006	WI	Sheboygan	80.0	81	72.7	73.6	72

TABLE IV.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	2016 Centered average	2016 Centered maximum	2023 Average	2023 Maximum	2021
040278011	AZ	Yuma	72.3	74	70.4	72.1	67
080690011	CO	Larimer	75.7	77	70.9	72.1	77
090099002	CT	New Haven	79.7	82	70.5	72.6	82
170310001	IL	Cook	73.0	77	68.2	71.9	71
170314201	IL	Cook	73.3	77	68.0	71.5	74
170317002	IL	Cook	74.0	77	68.5	71.3	73
350130021	NM	Dona Ana	72.7	74	70.8	72.1	80
350130022	NM	Dona Ana	71.3	74	69.7	72.4	75
350151005	NM	Eddy	69.7	74	69.7	74.1	77
350250008	NM	Lea	67.7	70	69.8	72.2	66
480391004	TX	Brazoria	74.7	77	70.4	72.5	75
481210034	TX	Denton	78.0	80	69.8	71.6	74
481410037	TX	El Paso	71.3	73	69.8	71.4	75
482010055	TX	Harris	76.0	77	70.9	71.9	77
482011034	TX	Harris	73.7	75	70.1	71.3	71
482011035	TX	Harris	71.3	75	67.8	71.3	71
530330023	WA	King	73.3	77	67.6	71.0	64
550590019	WI	Kenosha	78.0	79	70.8	71.7	74
551010020	WI	Racine	76.0	78	69.7	71.5	73

[166] In addition, there are 71 monitoring sites in California with projected 2023 maximum design values above the NAAQS. With two exceptions, as described in section IV.F of this document, the Agency is not making a determination in this action that these monitors are ozone transport receptors. The two exceptions are the two monitoring sites that represent air quality impacts to lands of the Morongo and Pechanga tribes. As explained in footnote 110 supra, we treat these as transport receptors that are impacted by emissions from California.

[167] 2016-centered averaged design values represent the average of the design values for 2016, 2017, and 2018. Similarly, the maximum 2016-centered design value is the highest measured design value from these three design value periods.

In total, in the 2023 base case there are a total of 33 projected modeling-based receptors nationwide including 14 nonattainment receptors in 9 different counties and 19 maintenance-only receptors in 13 additional counties (Harris County, TX, has both nonattainment and maintenance-only receptors).[168] Of the 14 nonattainment receptors in 2023, 7 remain nonattainment receptors, 5 are projected to become maintenance-only receptors and 2 are projected to be in attainment in 2026. Of the 19 maintenance-only receptors in 2023, 7 are projected to remain maintenance-only receptors and 12 are projected to be in attainment in 2026. The projected average and maximum design values in 2026 for all receptors are included in the Air Quality Modeling Final Rule TSD.

Comment: EPA received comments saying that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on EPA's modeling for the proposed rule are currently measuring nonattainment. Because 2023 is only a year later than the most recent measured data some commenters said that EPA should give greater weight to measured data when identifying downwind receptors.

Response: Based on an analysis of model projections for 2023 and recent trends in measured data, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* sites that are not modeling-based receptors).[169] Specifically, the EPA believes that monitoring sites with measured design values *and* 4th high maximum daily 8-hour average (MDA8) ozone based on 2021 *and* preliminary 2022 data have the greatest risk of continuing to have a problem attaining the standard in 2023, even when the modeling projects these sites will attain. These criteria are sufficiently conservative that we avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. We do not apply this methodology for the 2026 analytic year, because that year is sufficiently farther in the future that we do not believe there would be a reasonable basis to supplement our modeling analysis with this ''violating monitor'' methodology. By comparison, 2023 is so near in time that recent measured ozone levels can be used reasonably to project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action. The monitoring sites that meet these criteria, along with the corresponding measured and modeled data, are provided in Table IV.D–3.

For purposes of this action, we will treat these sites as an additional type of maintenance-only receptor. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment that they should be considered nonattainment receptors for purposes of this final rule. Rather, our authority for treating these sites as receptors in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523.

In this action, we identify ''violating monitor'' maintenance-only receptors for purposes of more firmly establishing that the states we have otherwise identified as linked at Step 2 in our modeling-based methodology can indeed be reasonably anticipated to be linked to air quality problems in downwind states in 2023 for reasons that extend beyond that methodology. In this sense, this approach is ''confirmatory'' and does not alter the geography of the final rule compared to the application of the modeling-based receptor definitions used at proposal. Rather, it strengthens the analytical basis for our Step 2 findings by establishing that many upwind states covered in this action are also projected to contribute above 1 percent of the NAAQS to these types of receptors. For purposes of this final rule, we will not finalize FIPs for any states that this analysis indicates contribute greater than 1 percent of the NAAQS only to a ''violating monitor'' receptor. Our analysis suggests this would be the case for two states, Kansas and Tennessee (see section IV.F of this document).[170] We are making no final decisions with respect to these states in this action and intend to address these states in a subsequent action.

TABLE IV.D–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (ppb) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS

Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P *	2021 4th high	2022 P 4th high
40070010	AZ	Gila	67.9	69.5	77	76	75	74

[168] The EPA's modeling also projects that three monitoring sites in the Uintah Basin (*i.e.,* monitor 490472003 in Uintah County, Utah, and monitors 490130002 and 490137011 in Duchesne County, Utah) will have average design values above the NAAQS in 2023. However, as noted in the proposed rule, the Uinta Basin nonattainment area was designated as nonattainment for the 2015 ozone NAAQS not because of an ongoing problem with summertime ozone (as is usually the case in other parts of the country), but instead because it violates the ozone NAAQS in winter. The main causes of the Uinta Basin's wintertime ozone are sources located at low elevations within the Basin, the Basin's unique topography, and the influence of the wintertime meteorologic inversions that keep ozone and ozone precursors near the Basin floor and restrict air flow in the Basin. Because of the localized nature of the ozone problem at these sites the EPA has not identified these three monitors as receptors in Step 1 of this final rule.

[169] In addition, we note that comparing the projected 2023 maximum design values at modeling-based receptors listed in Table IV.D–1 and Table IV.D–2 to the 2021 design values measured at these sites indicates that the projected maximum values are lower than the measured data at most receptors. These differences are particularly evident at receptors in coastal Connecticut and in Denver. (See Air Quality Modeling Final Rule TSD for details).

[170] We have not conducted an analysis in this action to determine whether violating-monitor receptors may exist in California.

TABLE IV.D–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (ppb) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS—Continued

Monitor ID	State	County	2023 Average	2023 Maximum	2021	2022 P *	2021 4th high	2022 P 4th high
40130019	AZ	Maricopa	69.8	70.0	75	77	78	76
40131003	AZ	Maricopa	70.1	70.7	80	80	83	78
40131004	AZ	Maricopa	70.2	70.8	80	81	81	77
40131010	AZ	Maricopa	68.3	69.2	79	80	80	78
40132001	AZ	Maricopa	63.8	64.1	74	78	79	81
40132005	AZ	Maricopa	69.6	70.5	78	79	79	77
40133002	AZ	Maricopa	65.8	65.8	75	75	81	72
40134004	AZ	Maricopa	65.7	66.6	73	73	73	71
40134005	AZ	Maricopa	62.3	62.3	73	75	79	73
40134008	AZ	Maricopa	65.6	66.5	74	74	74	71
40134010	AZ	Maricopa	63.8	66.9	74	76	77	75
40137020	AZ	Maricopa	67.0	67.0	76	77	77	75
40137021	AZ	Maricopa	69.8	70.1	77	77	78	75
40137022	AZ	Maricopa	68.2	69.1	76	78	76	79
40137024	AZ	Maricopa	67.0	67.9	74	76	74	77
40139702	AZ	Maricopa	66.9	68.1	75	77	72	77
40139704	AZ	Maricopa	65.3	66.2	74	77	76	76
40139997	AZ	Maricopa	70.5	70.5	76	79	82	76
40218001	AZ	Pinal	67.8	69.0	75	76	73	77
80013001	CO	Adams	63.0	63.0	72	77	79	75
80050002	CO	Arapahoe	68.0	68.0	80	80	84	73
80310002	CO	Denver	63.6	64.8	72	74	77	71
80310026	CO	Denver	64.5	64.8	75	77	83	72
90079007	CT	Middlesex	68.7	69.0	74	73	78	73
90110124	CT	New London	65.5	67.0	73	72	75	71
170310032	IL	Cook	67.3	69.8	75	75	77	72
170311601	IL	Cook	63.8	64.5	72	73	72	71
181270024	IN	Porter	63.4	64.6	72	73	72	73
260050003	MI	Allegan	66.2	67.4	75	75	78	73
261210039	MI	Muskegon	67.5	68.4	74	79	75	82
320030043	NV	Clark	68.4	69.4	73	75	74	74
350011012	NM	Bernalillo	63.8	66.0	72	73	76	74
350130008	NM	Dona Ana	65.6	66.3	72	76	79	78
361030002	NY	Suffolk	66.2	68.0	73	74	79	74
390850003	OH	Lake	64.3	64.6	72	74	72	76
480290052	TX	Bexar	67.1	67.8	73	74	78	72
480850005	TX	Collin	65.4	66.0	75	74	81	73
481130075	TX	Dallas	65.3	66.5	71	71	73	72
481211032	TX	Denton	65.9	67.7	76	77	85	77
482010051	TX	Harris	65.3	66.3	74	73	83	72
482010416	TX	Harris	68.8	70.4	73	73	78	71
484390075	TX	Tarrant	63.8	64.7	75	76	76	77
484391002	TX	Tarrant	64.1	65.7	72	77	76	80
484392003	TX	Tarrant	65.2	65.9	72	72	74	72
484393009	TX	Tarrant	67.5	68.1	74	75	75	75
490571003	UT	Weber	69.3	70.3	71	74	77	71
550590025	WI	Kenosha	67.6	70.7	72	73	72	71
550890008	WI	Ozaukee	65.2	65.8	71	72	72	72

* 2022 preliminary design values are based on 2022 measured MDA8 concentrations provided by state air agencies to the EPA's Air Quality System (AQS), as of January 3, 2023.

F. Pollutant Transport From Upwind States

1. Air Quality Modeling To Quantify Upwind State Contributions

This section documents the procedures the EPA used to quantify the impact of emissions from specific upwind states on ozone design values in 2023 and 2026 for the identified downwind nonattainment and maintenance receptors. The EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on downwind nonattainment and maintenance receptors for 8-hour ozone. CAMx employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations. The benefit of the photochemical model source apportionment technique is that all modeled ozone at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources.

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique [171] to quantify the contribution of 2023 and 2026 base case NO_X and VOC emissions from all sources in each state to the

[171] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

corresponding projected ozone design values in 2023 and 2026 at air quality monitoring sites. The CAMx OSAT/APCA model run was performed for the period May 1 through September 30 using the projected future base case emissions and 2016 meteorology for this time period. In the source apportionment modeling the Agency tracked (*i.e.,* tagged) the amount of ozone formed from anthropogenic emissions in each state individually as well as the contributions from other sources (*e.g.,* natural emissions).

In the state-by-state source apportionment model runs, the EPA tracked the ozone formed from each of the following tags:

• States—anthropogenic NO_X and VOC emissions from each state tracked individually (emissions from all anthropogenic sectors in a given state were combined);

• Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);

• Boundary Concentrations—concentrations transported into the air quality modeling domain;

• Tribes—the emissions from those tribal lands for which the Agency has point source inventory data in the 2016v3 emissions modeling platform (EPA did not model the contributions from individual tribes);

• Canada and Mexico—anthropogenic emissions from sources in the portions of Canada and Mexico included in the modeling domain (the EPA did not model the contributions from Canada and Mexico separately);

• Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and

• Offshore—combined emissions from offshore marine vessels and offshore drilling platforms.

The contribution modeling provided contributions to ozone from anthropogenic NO_X and VOC emissions in each state, individually. The contributions to ozone from chemical reactions between biogenic NO_X and VOC emissions were modeled and assigned to the ''biogenic'' category. The contributions from wildfire and prescribed fire NO_X and VOC emissions were modeled and assigned to the ''fires'' category. That is, the contributions from the ''biogenic'' and ''fires'' categories are not assigned to individual states nor are they included in the state contributions.

For the Step 2 analysis, the EPA calculated a contribution metric that considers the average contribution on the 10 highest ozone concentration days (*i.e.,* top 10 days) in 2023. This average contribution metric is intended to provide a reasonable representation of the contribution from individual states to projected future year design values, based on modeled transport patterns and other meteorological conditions generally associated with modeled high ozone concentrations at the receptor. An average contribution metric constructed in this manner is beneficial since the magnitude of the contributions is directly related to the magnitude of the design value at each site.

The analytic steps for calculating the contribution metric for the 2023 analytic year are as follows:

(1) Calculate the 8-hour average contribution from each source tag to each monitoring site for the time period of the 8-hour daily maximum modeled concentrations in 2023;

(2) Average the contributions and average the concentrations for the top 10 modeled ozone concentration days in 2023;

(3) Divide the average contribution by the corresponding average concentration to obtain a Relative Contribution Factor (RCF) for each monitoring site;

(4) Multiply the 2023 average design values by the 2023 RCF at each site to produce the average contribution metric values in 2023.[172]

This same approach was applied to calculate contribution metric values at individual monitoring sites for 2026.[173]

The resulting contributions from each tag to each monitoring site in the U.S. for 2023 and 2026 can be found in the docket for this final rule. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the Air Quality Modeling Final Rule TSD. The EPA's response to comments on the method for calculating the contribution metric can be found in the *RTC* document for this final rule.

The largest contribution from each state that is the subject of this rule to modeled 8-hour ozone nonattainment and maintenance receptors in downwind states in 2023 and 2026 are provided in Table IV.F–1 and Table IV.F–2, respectively. The largest contribution from each state to a ''violating monitor'' maintenance-only receptor is provided in Table IV.F–3.

TABLE IV.F–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.75	0.65
Arizona	0.54	1.69
Arkansas	0.94	1.21
California	35.27	6.31
Colorado	0.14	0.18
Connecticut	0.01	0.01
Delaware	0.44	0.56
District of Columbia	0.03	0.04
Florida	0.50	0.54
Georgia	0.18	0.17
Idaho	0.42	0.41
Illinois	13.89	19.09

[172] Note that a contribution metric value was not calculated for any receptor at which there were fewer than 5 days with model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in 2023. The monitoring site in Seattle, King County, Washington (530330023), was the only receptor which did not meet this criterion.

[173] To provide consistency in the contributions for 2023 and 2026, the contribution metric values for 2026 are based on the 2026 daily contributions for the same days that were used to calculate the contribution metric values for 2023.

TABLE IV.F–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023—Continued

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Indiana	8.90	10.03
Iowa	0.67	0.90
Kansas	0.46	0.52
Kentucky	0.84	0.79
Louisiana	9.51	5.62
Maine	0.02	0.01
Maryland	1.13	1.28
Massachusetts	0.33	0.15
Michigan	1.59	1.56
Minnesota	0.36	0.85
Mississippi	1.32	0.91
Missouri	1.87	1.39
Montana	0.08	0.10
Nebraska	0.20	0.36
Nevada	1.11	1.13
New Hampshire	0.10	0.02
New Jersey	8.38	5.79
New Mexico	0.36	1.59
New York	16.10	11.29
North Carolina	0.45	0.66
North Dakota	0.18	0.45
Ohio	2.05	1.98
Oklahoma	0.79	1.01
Oregon *	0.46	0.31
Pennsylvania	6.00	4.36
Rhode Island	0.04	0.01
South Carolina	0.16	0.18
South Dakota	0.05	0.08
Tennessee	0.60	0.68
Texas	1.03	4.74
Utah	1.29	0.98
Vermont	0.02	0.01
Virginia	1.16	1.76
Washington	0.16	0.09
West Virginia	1.37	1.49
Wisconsin	0.21	2.86
Wyoming	0.68	0.67

TABLE IV.F–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.20	0.69
Arizona	0.44	1.34
Arkansas	0.53	1.16
California	34.03	6.16
Colorado	0.04	0.17
Connecticut	0.00	0.01
Delaware	0.43	0.41
District of Columbia	0.03	0.02
Florida	0.46	0.17
Georgia	0.13	0.16
Idaho	0.27	0.36
Illinois	0.63	13.57
Indiana	1.06	8.53
Iowa	0.14	0.62
Kansas	0.14	0.42
Kentucky	0.79	0.76
Louisiana	4.57	9.37

TABLE IV.F–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026—Continued

[ppb]

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Maine	0.00	0.01
Maryland	1.06	0.92
Massachusetts	0.06	0.31
Michigan	1.39	1.47
Minnesota	0.15	0.32
Mississippi	0.29	1.15
Missouri	0.29	1.68
Montana	0.06	0.07
Nebraska	0.09	0.19
Nevada	0.67	0.90
New Hampshire	0.01	0.09
New Jersey	8.10	7.04
New Mexico	0.35	0.46
New York	12.65	12.34
North Carolina	0.40	0.42
North Dakota	0.09	0.17
Ohio	1.95	1.93
Oklahoma	0.19	0.74
Oregon *	0.26	0.41
Pennsylvania	5.47	4.94
Rhode Island	0.00	0.03
South Carolina	0.14	0.15
South Dakota	0.03	0.04
Tennessee	0.24	0.54
Texas	0.48	4.34
Utah	1.05	0.81
Vermont	0.01	0.02
Virginia	1.09	1.10
Washington	0.10	0.14
West Virginia	1.36	1.34
Wisconsin	0.17	0.18
Wyoming	0.40	0.59

TABLE IV.F–3—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE "VIOLATING MONITOR" MAINTENANCE-ONLY RECEPTORS

[ppb]

Upwind state	Largest contribution to downwind violating monitor maintenance-only receptors
Alabama	0.79
Arizona	1.62
Arkansas	1.16
California	6.97
Colorado	0.39
Connecticut	0.17
Delaware	0.42
District of Columbia	0.03
Florida	0.50
Georgia	0.31
Idaho	0.46
Illinois	16.53
Indiana	9.39
Iowa	1.13
Kansas	0.82
Kentucky	1.57
Louisiana	5.06
Maine	0.02
Maryland	1.14
Massachusetts	0.39
Michigan	3.47

TABLE IV.F–3—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE "VIOLATING MONITOR" MAINTENANCE-ONLY RECEPTORS—Continued

[ppb]

Upwind state	Largest contribution to downwind violating monitor maintenance-only receptors
Minnesota	0.64
Mississippi	1.02
Missouri	2.95
Montana	0.12
Nebraska	0.43
Nevada	1.11
New Hampshire	0.10
New Jersey	8.00
New Mexico	0.34
New York	12.08
North Carolina	0.65
North Dakota	0.35
Ohio	2.25
Oklahoma	1.57
Oregon *	0.36
Pennsylvania	5.20
Rhode Island	0.08
South Carolina	0.23
South Dakota	0.12
Tennessee	0.86
Texas	3.83
Utah	1.46
Vermont	0.03
Virginia	1.39
Washington	0.11
West Virginia	1.79
Wisconsin	5.10
Wyoming	0.42

* Does not include California monitoring sites.

2. Application of Contribution Screening Threshold

In Step 2 of the interstate transport framework, the EPA uses an air quality screening threshold to identify upwind states that contribute to downwind ozone concentrations in amounts sufficient to "link" them to these to downwind nonattainment and maintenance receptors. The contributions from each state to each downwind nonattainment or maintenance receptor that were used for the Step 2 evaluation can be found in the Air Quality Modeling Final Rule TSD.

The EPA applies an air quality screening threshold of 1 percent of the NAAQS, which has been used since the CSAPR rulemaking, including in the CSAPR Update, the Revised CSAPR Update, and numerous actions evaluating states' transport SIP submittals. The explanation for how this value was originally derived is available in the CSAPR rulemaking from 2011. *See* 76 FR 48208, 48237–38. As originally explained there, the application of a relatively low threshold is intended to capture a relatively large percentage of the contribution from upwind states to downwind receptors in light of the regional-scale, collective contribution problem associated with both ozone and $PM_{2.5}$ NAAQS. *Id.* The Agency also explained that the use of a higher threshold in transport rules prior to CSAPR was based on single-day maximum contribution, whereas in CSAPR (and continuing in subsequent rules including this one), the Agency uses a more robust, average contribution metric over multiple days. Thus, it was not the case that 1 percent of NAAQS was substantially more stringent than that prior approach. *Id.* at 48238. In the 2016 CSAPR Update, the EPA reviewed the 1 percent threshold (as coupled with multi-day averaging) and determined it was appropriate to continue to apply this threshold. The EPA compared the 1 percent threshold to a 0.5 percent of NAAQS threshold and a 5 percent of NAAQS threshold. The EPA found that the lower threshold did not capture appreciably more upwind state contribution compared to the 1 percent threshold, while the 5 percent threshold allowed too much upwind state contribution to drop out from further analysis.[174] The EPA continues to observe that nonattainment and maintenance receptors identified at Step 1 are impacted collectively by emissions from numerous upwind contributors. Therefore, application of a low, uniform screening threshold allows the EPA to identify upwind states that share a responsibility under the interstate transport provision to eliminate their significant contribution.

As we explained at proposal, the EPA recognizes that in 2018 it issued a memorandum indicating the potential for states to use a higher threshold at Step 2 in the development of their good neighbor SIP submissions where it could be technically justified. The August 2018 memorandum stated that "it may be reasonable and appropriate" for states to rely on an alternative 1 ppb threshold at Step 2.[175] (The memorandum also indicated that any

[174] *See* Final CSAPR Update Air Quality Modeling TSD, at 27–30 (EPA–HQ–OAR–2015–0596–0144). *See also* 86 FR 23054, 23085.

[175] August 2018 memo at 4.

higher alternative threshold, such as 2 ppb, would likely not be appropriate.) The EPA nonetheless proposed to fulfill its role under CAA section 110(c) in promulgating FIPs to directly implement good neighbor requirements, and in this role, proposed retaining use of the 1 percent threshold for all states. We noted that in several documents proposing transport SIP disapprovals, *see, e.g.,* 87 FR 9498 and 87 FR 9510 (Feb. 22, 2022), we explained that our experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds led the Agency to believe it may not be appropriate to continue to attempt to recognize alternative contribution thresholds at Step 2, either in the context of SIPs or FIPs.

We went on to explain that the EPA's experience since 2018 is that allowing for alternative Step 2 thresholds may be impractical or otherwise inadvisable for a number of additional policy reasons. For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. Using multiple different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns.[176] The application of different thresholds at Step 2 has the potential to result in inconsistent determination of good neighbor obligations. From the perspective of ensuring effective regional implementation of good neighbor obligations, the more important analysis is the evaluation of the emissions reductions needed, if any, to address a state's significant contribution after consideration of a multifactor analysis at Step 3, including a detailed evaluation that considers air quality factors and cost. We explained that while alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of alternative thresholds would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This could create significant equity and consistency problems among states.

The EPA further proposed that, in promulgating FIPs to address these obligations on a nationwide scale, national ozone transport policy would not be well-served by applying a single, less stringent threshold at Step 2. The EPA recognized in the August 2018 memo that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, the EPA noted at proposal that while this may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3. Considering the core statutory objective of ensuring elimination of *all* significant contribution to nonattainment or interference of the NAAQS in downwind states and the broad, regional nature of the collective contribution problem with respect to ozone, EPA could not identify a compelling policy imperative to move to a 1 ppb threshold.

In the proposal, we also found consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which used a Step 2 threshold of 1 percent of the NAAQS for two less protective ozone NAAQS) to be an important consideration. Continuing to use a 1 percent of NAAQS approach ensures that as the NAAQS are revised and made more stringent, an appropriate increase in stringency at Step 2 occurs, so as to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport for the more protective NAAQS.

The Agency also questioned whether it would be a good use of limited resources to attempt to further justify the use of alternative thresholds for certain states at Step 2 for purposes of the 2015 ozone NAAQS. Therefore, while EPA articulated the possibility of an alternative threshold in the August 2018 memorandum, the EPA concluded in the proposal that our experience and further evaluation since the issuance of that memo has revealed substantial programmatic and policy difficulties in attempting to implement this approach, and therefore we proposed to apply the 1 percent of NAAQS threshold.

Comment: Many commenters disagreed with our proposal to continue using a 1 percent of NAAQS threshold. They argued that the EPA was reversing course from its policy as articulated in the August 2018 memorandum and that the EPA was now bound to use a 1 ppb threshold rather than 1 percent of NAAQS, even in promulgating a FIP rather than evaluating SIPs.

Commenters further argued that a 1 ppb threshold would be more consistent with the EPA's ''significant impact level'' (SIL) guidance related to implementing prevention of significant deterioration (PSD) permitting requirements. They argued that the 1 percent threshold was below precision limits of regulatory ozone monitors, and they argued it was within the ''margin of error'' of the EPA's modeling.

Response: The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS threshold at Step 2 in this action to determine which states contribute to identified nonattainment and maintenance receptors. This approach ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. We do not agree that this approach is inconsistent with or a reversal in policy from the August 2018 memorandum, which only suggested that states in the development of their SIPs ''may'' be able to establish that 1 ppb could be an appropriate alternative threshold. The EPA has been consistent in that memorandum, and since that time, that final determinations on alternative thresholds would be made through rulemaking action, as the EPA is taking here.

The August 2018 memorandum made clear that the Agency had substantial doubts that any threshold greater than 1 ppb (such as 2 ppb) would be acceptable, and the Agency is affirming that a threshold higher than 1 ppb would not be justified under any circumstance for purposes of this action. No commenter credibly provided a basis for using a threshold even higher than 1 ppb, and so this issue is primarily limited to the difference between a 0.7 ppb threshold (the 1 percent of the NAAQS threshold discussed previously in this section) and a 1.0 ppb threshold. Therefore, before proceeding in responding to these comments, we note that this issue is only relevant to a small number of states whose contributions to any receptor are above 1 percent of the NAAQS but lower than 1 ppb. Under the 2016v3 modeling of 2023 being used in this final rule, the states in this rule with contributions that fall between 0.70 ppb and 1 ppb are Alabama, Kentucky, and Minnesota. Similarly, the EPA applies the 1 percent threshold in its 2026 modeling projections to determine if any states will not be linked to an ozone receptor by that year, and therefore should not be subject to the more stringent requirements that take effect in 2026. The states in this rule in that year with contribution between 0.70 ppb and 1 ppb are

[176] We note that Congress has placed on the EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

Kentucky, Nevada, and Oklahoma. For all other states covered in this action, at least one linkage exists in 2023 (and, as relevant, in 2026) that is greater than 1 ppb, and therefore the question of whether the EPA must recognize a 1 ppb threshold would not have a dispositive effect on the regulatory determination being made at Step 2.

The 1 percent of the NAAQS threshold is consistent with the Step 2 approach that the EPA applied in CSAPR for the 1997 ozone NAAQS and has subsequently been applied in the CSAPR Update and Revised CSAPR Update when evaluating determining interstate transport obligations for the 2008 ozone NAAQS. The EPA continues to find 1 percent of the ozone NAAQS to be an appropriate threshold. For ozone, as the EPA found in CAIR, CSAPR, and the CSAPR Update, a portion of the nonattainment and maintenance problems in the U.S. results from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and other sources. The EPA's analysis shows that the ozone transport problem being analyzed in this rule is still the result of the collective impacts of emissions from multiple upwind contributors. Therefore, application of a consistent contribution threshold is necessary to identify those upwind states that should have responsibility for addressing their contribution (to the extent found ''significant'' at Step 3) to the downwind nonattainment and maintenance problems to which they collectively contribute. Where a great number of geographically dispersed emissions sources contribute to a downwind air quality problem, which is the case for ozone, EPA believes that, in the context of CAA section 110(a)(2)(D)(i)(I), a state-level threshold of 1 percent of the NAAQS is a reasonably small enough value to identify only the greater-than-de minimis contributors yet is not so large that it unfairly focuses attention for further action only on the largest single or few upwind contributors. Continuing to use 1 percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows the EPA (and states) to apply a consistent framework to evaluate interstate emissions transport under the interstate transport provision from one NAAQS to the next. *See* 86 FR 23054, 23085; 81 FR 74504, 74518; 76 FR 48208, 48237–38.

Further, the EPA notes that the role of the Step 2 threshold is limited and just one step in the larger 4-Step Framework. It serves to screen in states for further evaluation of emissions control opportunities applying a multifactor analysis at Step 3. Thus, as the Supreme Court has recognized, the contribution threshold essentially functions to exclude states with ''*de miminis*'' impacts. *EME Homer City,* 572 U.S. 489, 500.

Comments related to the August 2018 memorandum argued that the EPA legally committed itself to approving SIP submissions from states with contributions below 1 ppb and so now the EPA must apply that threshold in this FIP action. (Comments regarding this issue as related to the EPA's action on SIPs is addressed in that rulemaking and is beyond the scope of this action.) This is not what the memorandum said. The memorandum merely provided an analysis regarding ''the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states.'' [177] It interpreted ''that information to make recommendations about what thresholds *may* be appropriate for use in'' SIP submissions (emphasis added).[178] Specifically, the August 2018 memorandum said, ''Because the amount of upwind collective contribution capture with the 1 percent and the 1 ppb thresholds is *generally comparable, overall, we believe it may be* reasonable and appropriate for states to use a 1 ppb contribution threshold, as an alternative to a 1 percent threshold, at Step 2 of the 4-step framework in developing their SIP revisions addressing the good neighbor provision for the 2015 ozone NAAQS'' (emphasis added).[179] Thus, the text of the August 2018 memorandum in no way committed that the EPA would be using a 1 ppb threshold going forward either in its evaluation of SIPs or in promulgating a FIP. The August 2018 memorandum indicated that ''[f]ollowing these recommendations does not ensure that EPA will approve a SIP revision in all instances where the recommendations are followed, as the guidance may not apply to the facts and circumstances underlying a particular SIP. Final decisions by the EPA to approve a particular SIP revision will only be made based on the requirements of the statute and will only be made following an air agency's final submission of the SIP revision to the EPA, and after appropriate notice and opportunity for public review and comment.'' [180] Further, the August 2018 memorandum said that ''EPA and air agencies should consider whether the recommendations in this guidance are appropriate for each situation.'' [181] The memorandum said nothing regarding what threshold the EPA would apply if promulgating a FIP.

As explained in the SIP disapproval action and again here, the EPA finds it would not be sound policy to apply an alternative contribution threshold or thresholds to one or more states within the 4-step interstate transport framework for the 2015 ozone NAAQS. However, the EPA disagrees with commenters' claims that the agency has reversed course on applying the August 2018 memorandum, because the memorandum never adopted a view that the use of 1 ppb or other alternative thresholds would in fact be acceptable. Although the EPA said at proposal that the EPA may rescind the guidance in the future, we took comment on the subject and also stated, ''EPA is not at this time rescinding the August 2018 memorandum.'' [182] The EPA is not formally rescinding the August 2018 memorandum in this action or at this time. However, it is not required that agencies must ''rescind'' a memorandum or guidance the moment it becomes outdated or called into question. The August 2018 memorandum was not issued through notice-and-comment rulemaking and is not binding on the Agency or other parties. While the *willingness* of the Agency as expressed in that memorandum to entertain the possibility of an alternative threshold of 1 ppb may be considered a kind of policy position, agencies may change their non-binding policies without going through notice and comment rulemaking. *Catawba County* v. *EPA,* 571 F.3d 20, 34 (D.C. Cir. 2009). In this case, we went through notice and comment rulemaking on this topic in the SIP-disapproval action (88 FR 9336) and here, even though the August 2018 memorandum was issued without such opportunity for public input. We further address the basis for the consistent use of a 1 percent of NAAQS threshold and summarize our conclusions under the *FCC* v. *Fox* factors below.

We continue to believe, as set forth in our proposed action, that national ozone transport policy is not well served by

[177] August 2018 memorandum, at 1.

[178] *Id.*

[179] *Id.* at 4.

[180] *Id.* at 1.

[181] *Id.*

[182] 87 FR 9545, 9551 (Feb. 22, 2022) (Alabama, Mississippi, Tennessee); 87 FR 9498, 9510 (Feb. 22, 2022) (Kentucky); 87 FR 9838, 9844 (Feb. 22, 2022) (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin); 87 FR 9798, 9807, 9813, 9820 (Feb. 22, 2022) (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9533, 9542 (Feb. 22, 2022) (Missouri); 87 FR 31470, 31479 (May 24, 2022) (Utah); 87 FR 31495, 31504 (May 24, 2022) (Wyoming); 87 FR 31485, 31490 (May 24, 2022) (Nevada).

allowing for less protective thresholds than 1 percent of the NAAQS at Step 2. Furthermore, the EPA disagrees with commenters who suggest that national consistency is an inappropriate consideration in the context of interstate ozone transport. The Good Neighbor provision, CAA section 110(a)(2)(D)(i)(I), requires to a unique degree of concern for consistency, parity, and equity across state lines.[183] For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. Based on the EPA's review of good neighbor SIP submissions to-date and after further consideration of the policy implications of attempting to recognize an alternative Step 2 threshold for certain states, the Agency concludes that the attempted use of different thresholds at Step 2 with respect to the 2015 8-hour ozone NAAQS raises substantial policy consistency and practical implementation concerns. The availability of different thresholds at Step 2 has the potential to result in inconsistent application of good neighbor obligations based solely on the strength of a state's SIP submission at Step 2 of the 4-step interstate transport framework. The steps of the analysis that lead up to evaluating emissions reductions opportunities to address states' significant contribution at Step 3 should be applied on a consistent basis. Where alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of an alternative threshold would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This can create significant equity and consistency problems among states and could lead to ineffective or inefficient approaches to eliminating significant contribution.

One commenter suggested the EPA could address this potentially inequitable outcome by simply adopting a 1 ppb contribution threshold for all states. However, the August 2018 memorandum did not conclude that 1 ppb would be appropriate for all states and the EPA does not view that conclusion to be supported at present. The EPA recognized in the August 2018 memorandum that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, while this may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold for every state. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3 (*e.g.,* roughly 7 percent of total upwind state contribution was lost according to the modeling underlying the August 2018 memorandum; in the EPA's 2016v2 modeling, the amount lost is 5 percent; in the EPA's 2016v3 modeling used for final, the amount lost is also 5 percent). Further, this logic has no end point. A similar observation could be made with respect to any incremental change. For example, should the EPA next recognize a 1.2 ppb threshold because that would only cause some small additional loss in capture of upwind state contribution as compared to 1 ppb? If the only basis for moving to a 1 ppb threshold is that it captures a ''similar'' (but actually smaller) amount of upwind contribution, then there is no basis for moving to that threshold at all. Considering the core statutory objective of ensuring elimination of all significant contribution to nonattainment or interference with maintenance of the NAAQS in other states and the broad, regional nature of the collective contribution problem with respect to ozone, we continue to find no compelling policy reason to adopt a new threshold for all states of 1 ppb.

Nor have commenters explained why use of a 1 ppb threshold would be appropriate under the more protective 2015 ozone NAAQS when a 1 percent of the NAAQS contribution threshold has been used for less protective ozone NAAQS. To illustrate, a state contributing greater than 0.75 ppb but less than 1 ppb to a receptor under the 2008 ozone NAAQS was ''linked'' at Step 2,[184] but if a 1 ppb threshold were used for the 2015 ozone NAAQS then that same state would *not* be ''linked'' to a receptor at Step 2 under a NAAQS that is set to be *more* protective of human health and the environment. Consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which all used the 1 percent of the NAAQS for less protective ozone NAAQS), is an important consideration. We affirm our view in CSAPR that continuing to use a 1 percent of NAAQS approach ensures that if the NAAQS are revised and made more stringent, an appropriate increase in stringency at Step 2 occurs, so as to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport. *See* 76 FR 48208, 48237–38.

We note further that application of a 1 percent of NAAQS threshold has been the EPA's consistent approach in each of our notice-and-comment rulemakings beginning with CSAPR and continuing with the CSAPR Update, the Revised CSAPR Update, and numerous actions on ozone transport SIP submissions. In each case, the 1 percent of the NAAQS threshold was subject to rigorous vetting through public comment and the Agency's response to those comments, including through the use of analytical evaluations of alternative thresholds. *See, e.g.,* 81 FR 74518–19. By contrast, the August 2018 memorandum was not issued through notice-and-comment rulemaking procedures, and the EPA was careful to caveat its utility and ultimate reliability for that reason.

The EPA disagrees with claims that the EPA is applying the August 2018 memorandum inconsistently based on the EPA's actions with regard to Arizona, Iowa, and Oregon. The EPA withdrew a previously proposed approval of Iowa's SIP submission that was premised on a 1 ppb contribution threshold, and re-proposed and finalized approval of that SIP based on a different rationale using a 1 percent of the NAAQS contribution threshold. 87 FR 9477 (Feb. 22, 2022); 87 FR 22463 (April 15, 2022). The EPA also disagrees with any claim that Oregon and Arizona were ''allowed'' to use a 1 ppb or higher threshold. The EPA approved Oregon's SIP submission for the 2015 ozone NAAQS on May 17, 2019, and both Oregon and the EPA relied on a 1 percent of the NAAQS contribution threshold. 84 FR 7854, 7856 (March 5, 2019) (proposal); 84 FR 22376 (May 17, 2019) (final). In the proposal for this action, the EPA explained it was not proposing to conduct an error correction for Oregon even though updated modeling indicated Oregon contributed above 1 percent of the NAAQS to monitors in California.

The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information). In 2016, the EPA approved Arizona's SIP for the earlier 2008 ozone NAAQS based on a similar rationale with regard to certain monitors in California. 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule). We are deferring finalizing a finding at this time that such a rationale is appropriate

[183] EPA notes that Congress has placed on EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

[184] *See* 86 FR 23054, 23058 (April 30, 2021).

with respect to the more protective 2015 ozone NAAQS. While Arizona and Oregon's interstate transport obligations for the 2015 ozone NAAQS remain pending (along with several other states), there is no inconsistency in the treatment of these states or any other state at Step 2.

Some commenters claim the EPA must use a 1 ppb threshold based on the identification of 1 ppb as a significance threshold in one step of the PSD permitting process. The EPA's SIL guidances, however, relate to a different provision of the Clean Air Act regarding implementation of the prevention of significant deterioration (PSD) permitting program. This program applies in areas that have been designated attainment of the NAAQS and is intended to ensure that such areas remain in attainment even if emissions were to increase as a result of new sources or major modifications to existing sources located in those areas. This purpose is different than the purpose of the good neighbor provision, which is to assist downwind areas (in some cases hundreds or thousands of miles away) in resolving ongoing nonattainment of the NAAQS or difficulty maintaining the NAAQS through eliminating the emissions from other states that are significantly contributing to those problems. In addition, as discussed in preceding paragraphs, the purpose of the Step 2 threshold within the EPA's interstate transport framework for ozone is to broadly sweep in all states contributing to identified receptors above a de minimis level in recognition of the collective-contribution problem associated with regional-scale ozone transport. The threshold used in the context of PSD SIL serves a different purpose, and so it does not follow that they should be made equivalent. Further, commenters incorrectly associate the EPA's Step 2 contribution threshold with the identification of "significant" emissions (which does not occur until Step 3), and so it is not the case that the EPA is interpreting the same term differently.

The EPA has previously explained this distinction between the good neighbor framework and PSD SILs. *See* 70 FR 25162, 25190–25191 (May 12, 2005); 76 FR 48208, 48237 (Aug. 8, 2011). Importantly, the implication of the PSD SIL threshold is not that single-source contribution below this level indicates the absence of a contribution or that no emissions control requirements are warranted. Rather, the PSD SIL threshold addresses whether further, more comprehensive, multi-source review or analysis of air quality impacts are required of the source to support a demonstration that it meets the criteria for a permit. A source with estimated impacts below the PSD SIL may use this to demonstrate that it will not cause or contribute (as those terms are used within the PSD program) to a violation of an ambient air quality standard, but is still subject to meeting applicable control requirements, including best available control technology, designed to moderate the source's impact on air quality.

Moreover, other aspects of the technical methodology in the SILs guidance compared to the good neighbor framework make a direct comparison between these two values misleading. For instance, in PSD permit modeling using a single year of meteorology the maximum single-day 8-hour contribution is evaluated with respect to the SIL. The purpose of the contribution threshold at Step 2 of the 4-step good neighbor framework is to determine whether the average contribution from a collection of sources in a state is small enough not to warrant any additional control for the purpose of mitigating interstate transport, even if that control were highly cost effective. Using a 1 percent of the NAAQS threshold is more appropriate for evaluating multi-day average contributions from upwind states than a 1 ppb threshold applied for a single day, since that lower value of 1 percent of the NAAQS will capture variations in contribution. If EPA were to use a single day reflecting the maximum amount of contribution from an upwind state to determine whether a linkage exists at Step 2, commenters' arguments for use of the PSD SIL might have more force. This would in effect be a return to the pre-CSAPR contribution calculation methodology of using a single day, *see* 76 FR 48238. However, that would likely cause more states to become linked, not less. And in any case, consistent with the method in our modeling guidance for projecting future attainment/nonattainment and as the EPA concluded in 2011 in CSAPR, the present good neighbor methodology of using multiple days provides a more robust approach to establishing that a linkage exists at the state level than relying on a single day of data.

A commenter also claimed the 1 percent of NAAQS threshold is inconsistent with the standards of precision for Federal reference monitors for ozone and the rounding requirements found in 40 CFR part 50, appendix U, Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone. Commenter claimed that the 1 percent contribution threshold of 0.7 ppb is lower than the manufacturer's reported precision of these reference monitors and that the requirements found in Appendix U truncates monitor values of 0.7 ppb to 0 ppb. However, the commenter is mistaken in applying criteria related to the precision of monitoring technology to the modeling methodology by which we project contributions when quantifying and evaluating interstate transport at Step 2. Indeed, contributions by source or state cannot be derived from the total ambient concentration of ozone at a monitor at all but must be apportioned through modeling. Under our longstanding methodology for doing so, the contribution values identified from upwind states are based on a robust assessment of the average impact of each upwind state's ozone-precursor emissions over a range of scenarios, as explained in the 2016v3 modeling's Air Quality Modeling Final Rule TSD, in the docket for this rule, Docket ID No. EPA–HQ–OAR–2021–0668. This analysis is in no way connected with or dependent on monitoring instruments' precision of measurement. *See EME Homer City,* 795 F.3d 118, 135–36 ("[A] model is meant to simplify reality in order to make it tractable.' ") (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994).

To the extent that commenters argue that the EPA consider a less stringent threshold as a result of modeling uncertainty, the EPA disagrees with this notion. The EPA has successfully applied a 1 percent of NAAQS threshold to identify linked upwind states using modeling in three prior FIP rulemakings and numerous state-specific actions on good neighbor obligations. This continues to be a reasonable approach, and indeed courts have repeatedly declined to establish bright line criteria for model performance. In upholding the EPA's approach to evaluating interstate transport in CSAPR, the D.C. Circuit held that it would not "invalidate EPA's predictions solely because there might be discrepancies between those predictions and the real world. That possibility is inherent in the enterprise of prediction." *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118, 135 (2015). "[T]he fact that a 'model does not fit every application perfectly is no criticism; a model is meant to simplify reality in order to make it tractable.' " *Id.* at 135–36 (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (D.C. Cir. 1994). *See also Sierra Club* v. *EPA,* 939 F.3d 649, 686–87 (5th Cir. 2019) (upholding EPA's modeling in the face of complaints regarding an alleged ''margin of error,'' noting challengers face a ''considerable burden'' in overcoming a ''presumption of regularity'' afforded ''the EPA's choice of analytical methodology'') (citing *BCCA Appeal Grp.* v. *EPA,* 355 F.3d 817, 832 (5th Cir. 2003)).

The Agency will continue to use the CAMx model to evaluate contributions from upwind states to downwind areas. The agency has used CAMx routinely in previous notice and comment transport rulemakings to evaluate contributions relative to the 1 percent threshold for both ozone and $PM_{2.5}$. In fact, in the original CSAPR, the EPA found that ''[t]here was wide support from commenters for the use of CAMx as an appropriate, state-of-the science air quality tool for use in the [Cross-State Air Pollution] Rule. There were no comments that suggested that the EPA should use an alternative model for quantifying interstate transport.'' 76 FR 48229 (August 8, 2011). In this action, the EPA has taken a number of steps based on comments and new information to ensure to the greatest extent the accuracy and reliability of its modeling projections at Step 1 and 2, as discussed elsewhere in this section.

The EPA disagrees with commenters that case law reviewing changes in agency positions such as *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502, 515 (2009), is applicable with respect to this issue. As explained above, under the terms of the August 2018 memorandum, the Agency did not conclude that the use of an alternative contribution threshold was justified for any states. But even if it were found that the Agency's position had changed between this rulemaking action and the August 2018 memorandum, the *FCC* v. *Fox* factors are met. We have explained above that there are good reasons for continuing to use a 1 percent of NAAQS threshold. We also are aware that we are not using a 1 ppb threshold despite acknowledging the potential for doing so in the August 2018 memorandum. We do not believe that any party has a serious reliance interest that would be sufficient to overcome the countervailing public interest that is served through the EPA's determination to maintain continuity with its longstanding, more protective 1 percent of NAAQS threshold in this action. *Cf.* 88 FR 9373 (reviewing reliance in the context of the SIP-disapproval action).

The EPA therefore will continue its longstanding practice of applying the 1 percent of NAAQS threshold in this action.

a. States That Contribute Below the Screening Threshold

Based on the EPA's modeling and considering measured data at violating monitors, the contributions from each of the following states to nonattainment or maintenance-only receptors in the 2023 analytic year are below the 1 percent of the NAAQS threshold: Colorado, Connecticut, the District of Columbia, Delaware, Florida, Georgia, Idaho, Maine, Massachusetts, Montana, Nebraska, New Hampshire, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, Vermont, and Washington.[185] The EPA has already approved these states' 2015 ozone good neighbor SIP submittals. Because the contributions from these states to projected downwind air quality problems are below the screening threshold in the current modeling, these states are not within the scope of this final rule. Additionally, the EPA has made final determinations that two states outside the modeling domain for the air quality modeling analyzed in this final rulemaking—Hawaii [186] and Alaska [187]—do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state.

With respect to Wyoming, our methodology when applied using the 2016v3 modeling suggests that whether the state is linked is uncertain and warrants further analysis. The EPA intends to expeditiously review its assessment with respect to Wyoming and take action addressing Wyoming's good neighbor obligations for the 2015 ozone NAAQS through a separate action.

b. States That Contribute at or Above the Screening Threshold

Based on the maximum downwind contributions in Table IV.F–1, the Step 2 analysis identifies that the following 21 states contribute at or above the 0.70 ppb threshold to downwind nonattainment receptors in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. Based on the maximum downwind contributions in Table IV.F–1, the following 23 states contribute at or above the 0.70 ppb threshold to downwind modeling-based maintenance-only receptors in 2023: Arizona, Arkansas, California, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New Mexico, New York, Ohio, Oklahoma, Texas, Virginia, West Virginia, and Wisconsin. Based on the maximum downwind contribution in Table IV.F–3, the following additional states contribute at or above the 0.70 ppb threshold to downwind violating monitor maintenance-only receptors in 2023: Kansas and Tennessee. (However, the EPA is not taking final action based on this analytical result for these two states at this time.) The levels of contribution between each of these linked upwind states and downwind nonattainment receptors and maintenance-only receptors are provided in the Air Quality Modeling Final Rule TSD.

Among the linked states are several western states—California, Nevada, and Utah. While the EPA has not previously included action on linked western states in its prior CSAPR rulemakings, the EPA has consistently applied the 4-step framework in evaluating good neighbor obligations from these states. On a case-by-case basis, the EPA has found in some instances with respect to the 2008 ozone NAAQS that a unique consideration has warranted approval of a western state's good neighbor SIP submittal that might otherwise be found to contribute above 1 percent of the NAAQS without concluding that additional emissions reductions are required at Step 3 of the framework.[188] The EPA has also explained in prior actions that its air quality modeling is reliable for assessing downwind air quality problems and ozone transport contributions from upwind states throughout the nationwide modeling domain.[189] The EPA is deferring finalizing a finding at this time for Oregon (*see* section IV.G of this document for additional information).

As explained in the following section, the EPA is not, in this action, altering its prior approval of Oregon's good neighbor SIP submission for the 2015 ozone NAAQS. For the remaining western states included in this rule, the EPA's modeling supports a conclusion that these states are linked above the

[185] The status of monitoring sites in California to which Oregon may be linked is under review. *See* section IV.G.

[186] The EPA approved Hawaii's 2015 ozone transport SIP on December 27, 2021. *See* 86 FR 73129.

[187] The EPA approved Alaska's 2015 ozone transport SIP on December 18, 2019. *See* 84 FR 69331.

[188] *See* interstate transport approval actions under the 2008 ozone NAAQS for Arizona, California, and Wyoming at 81 FR 36179 (June 6, 2016), 83 FR 65093 (December 19, 2018), and 84 FR 14270 (April 10, 2019)), respectively.

[189] *See* 81 FR 71991 (October 19, 2016), 82 FR 9155 (February 3, 2017).

contribution threshold to identified ozone transport receptors in downwind states, and therefore, consistent with the treatment of all other states within the modeling domain, the EPA proposes to proceed to evaluate these states for a determination of ''significant contribution'' at Step 3.

In conclusion, as described above, states with contributions that equal or exceed 1 percent of the NAAQS to either nonattainment or maintenance-only receptors are identified as ''linked'' at Step 2 of the good neighbor framework and warrant further analysis for significant contribution to nonattainment or interference with maintenance under Step 3. The EPA finds that for purposes of this final rule, the following 23 states are linked at Step 2 in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. In addition, the EPA finds that the following 20 States are linked at Step 2 in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia. We note that our updated modeling for this final rule shows that two states, Minnesota and Wisconsin, that we found linked in 2026 at proposal are no longer projected to be linked in that year but are linked in 2023.[190] As at proposal, Alabama is only projected to be linked in 2023, not 2026.

For six states, the EPA's analysis at this time indicates that a linkage may exist in 2023 for which the EPA had not proposed FIP requirements, or the updated analysis for this final rule suggests that linkages we had previously found in the proposed action are now uncertain and warrant further analysis. The EPA intends to expeditiously address these states in a separate action or actions: Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming.

G. Treatment of Certain Monitoring Sites in California and Implications for Oregon's Good Neighbor Obligations for the 2015 Ozone NAAQS

The EPA previously approved Oregon's September 25, 2018 transport SIP submittal for the 2015 ozone NAAQS on May 17, 2019 (84 FR 22376), because in an earlier round of modeling Oregon was not projected to contribute above 1 percent of the NAAQS to any downwind receptors. In the EPA's updated modeling used at proposal (2016v2) and again in the final modeling (2016v3), Oregon is modeled to contribute above the 1 percent of NAAQS threshold to several monitoring sites in California that would generally meet the EPA's definition of nonattainment or maintenance ''receptors'' at Step 1.[191] At proposal, the EPA explained that our analysis of the nature of the air quality problem at these monitoring sites led us to propose a determination that these monitoring sites should not be treated as receptors for purposes of determining interstate transport obligations of upwind states under CAA section 110(a)(2)(D)(i)(I). We explained that we reached this conclusion at Step 1 of our 4-step framework.

The EPA previously made a similar assessment of the nature of certain other monitoring sites in California in approving Arizona's 2008 ozone NAAQS transport SIP submittal.[192] There, the EPA noted that a ''factor [. . .] relevant to determining the nature of a projected receptor's interstate transport problem is the magnitude of ozone attributable to transport from all upwind states collectively contributing to the air quality problem.'' [193] The EPA observed that only one upwind state (Arizona) was linked above 1 percent of the 2008 ozone NAAQS to the two relevant monitoring sites in California, and the cumulative ozone contribution from all upwind states to those sites was 2.5 percent and 4.4 percent of the total ozone, respectively. The EPA determined the size of those cumulative upwind contributions was ''negligible, particularly when compared to the relatively large contributions from upwind states in the East or in certain other areas of the West.'' [194] In that action, the EPA concluded the two California sites to which Arizona was linked should not be treated as receptors for the purposes of determining Good Neighbor obligations for the 2008 ozone NAAQS.[195]

Comment: Commenters criticized what they considered to be unfair treatment of Oregon, stating that the EPA is applying a higher contribution threshold than it applies to other states. Commenters argued that EPA has not established a specific threshold for why the level of upwind-state impact at these sites should not be considered meaningful. Commenters argued that our analysis ignored the fact that there are many monitoring sites in California to which Oregon contributes above 1 percent of the NAAQS. Commenters state that EPA has failed to explain why Oregon is not subject to this rulemaking, while other states contribute lower total downwind ozone contributions and fewer receptors. Commenters concluded that since Oregon is linked it should be subject to the same emissions control determinations at Step 3 and 4 as every other state, or otherwise apply the same ''nature of the air quality problem'' consideration to eliminate other receptors.

Response: The EPA acknowledges that several commenters opposed the proposed treatment of Oregon and the California monitoring sites to which it is linked in the proposed and final modeling. We also recognize that other commenters expressed confusion regarding the role of this proposed determination at Step 1 and how it relates to the longstanding 4-step interstate transport framework that the EPA is otherwise applying in this action. In recognition of these concerns and the need to give further thought to the appropriate treatment of both upwind states and downwind receptors in these circumstances, the EPA is deferring finalizing a finding at this time for Oregon. The current approval of the state's SIP submission will remain in place for the time being, pending further review. We make no final determination in this action regarding whether the California monitoring sites at issue should or should not be treated as receptors for purposes of addressing interstate transport for the 2015 ozone NAAQS.

V. Quantifying Upwind-State NO_X Emissions Reduction Potential To Reduce Interstate Ozone Transport for the 2015 Ozone NAAQS

A. The Multi-Factor Test for Determining Significant Contribution

This section describes the EPA's methodology at Step 3 of the 4-step framework for identifying upwind emissions that constitute ''significant'' contribution for the states subject to this final rule and focuses on the 23 states with FIP requirements identified in the

[190] Minnesota and Wisconsin were linked to maintenance-only receptors in Cook County, IL in 2023. Minnesota and Wisconsin are not linked in 2026 because the 2026 average and maximum design values at the monitoring sites are projected to show attainment.

[191] Monitors are included in the docket for this rulemaking. While EPA is providing information about cumulative upwind contribution to the California monitors, the Agency is not making a determination in this action that these monitors are ozone transport receptors.

[192] 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule).

[193] 81 FR 15203.

[194] *Id.*

[195] *Id.*

previous sections. Following the existing framework as applied in the prior CSAPR rulemakings, the EPA's assessment of linked upwind state emissions is based primarily on analysis of several alternative levels of NO_X emissions control stringency applied uniformly across all of the linked states. The analysis includes assessment of non-EGU stationary sources in addition to EGU sources in the linked upwind states.

The EPA applies a multi-factor test—the same multi-factor test that was used in CSAPR, the CSAPR Update, and the Revised CSAPR Update [196]—to evaluate increasing levels of uniform NO_X control stringency. The multi-factor test, which is central to EPA's Step 3 quantification of significant contribution, considers cost, available emissions reductions, downwind air quality impacts, and other factors to determine the appropriate level of uniform NO_X control stringency that would eliminate significant contribution to downwind nonattainment or maintenance receptors. The selection of a uniform level of NO_X emissions control stringency across all of the linked states, reflected as a representative cost per ton of emissions reduction (or a weighted average cost per ton in the case of EPA's non-EGU and EGU analysis for 2026 mitigation measures), also serves to apportion the reduction responsibility among collectively contributing upwind states. This approach to quantifying upwind state emission-reduction obligations using uniform cost was reviewed by the Supreme Court in *EME Homer City Generation,* which held that using such an approach to apportion emissions reduction responsibilities among upwind states that are collectively responsible for downwind air quality impacts ''is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address.'' 572 U.S. at 519.

There are four stages in developing the multi-factor test: (1) identify levels of uniform NO_X control stringency; (2) evaluate potential NO_X emissions reductions associated with each identified level of uniform control stringency; (3) assess air quality improvements at downwind receptors for each level of uniform control stringency; and (4) select a level of control stringency considering the identified cost, available NO_X emissions reductions, and downwind air quality impacts, while also ensuring that emissions reductions do not unnecessarily over-control relative to the contribution threshold or downwind air quality.

As mentioned in section III.A.2 of this document, commenters on the proposed rule and previous ozone transport rules have suggested that the EPA should regulate VOCs as an ozone precursor. For this final rule, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Of the total upwind-downwind linkages in 2023, the contributions from NO_X emissions comprise 80 percent or more of the total anthropogenic contribution for nearly all of the linkages (121 out of 124 total). Across all receptors, the contribution from NO_X emissions ranges from 84 percent to 97 percent of the total anthropogenic contribution from upwind states. This review of the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the final rule under are primarily NO_X-limited, rather than VOC-limited. Therefore, the EPA continues to find that regulation of VOCs as an ozone precursor in upwind states is not necessary to eliminate significant contribution or interference with maintenance in downwind areas in this final rule. The remainder of this section focuses on EPA's strategy for reducing regional-scale transport of ozone by targeting NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas.

For both EGUs and non-EGUs, section V.B of this document describes the available NO_X emissions controls that the EPA evaluated for this final rule and their representative cost levels (in 2016$). Section V.C of this document discusses EPA's application of that information to assess emissions reduction potential of the identified control stringencies. Finally, section V.D of this document describes EPA's assessment of associated air quality impacts and EPA's subsequent identification of appropriate control stringencies considering the key relevant factors (cost, available emissions reductions, and downwind air quality impacts).

This multi-factor approach is consistent with EPA's approach in prior transport actions, such as CSAPR. In addition, as was evaluated in the CSAPR Update and Revised CSAPR Update, the EPA evaluated whether, based on particularized evidence, its selected control strategy would result in over-control for any upwind state by examining whether an upwind state is linked solely to downwind air quality problems that could have been resolved at a lesser threshold of control stringency and whether an upwind state could reduce its emissions below the 1 percent air quality contribution threshold at a lesser threshold of control stringency. This analysis is described in section V.D of this document.

Finally, while the EPA has evaluated potential emissions reductions from non-EGU sources in prior rules and found certain non-EGU emissions reductions should inform the budgets established in the NO_X SIP Call, this is the first action for which the EPA is finalizing non-EGU emissions reductions within the context of the specific, 4-step interstate transport framework established in CSAPR. The EPA applies its multi-factor test to non-EGUs and independently evaluates non-EGU industries in a consistent but parallel track to its Step 3 assessment for EGUs. This is consistent with the parallel assessment approach taken for EGUs and non-EGUs in the Revised CSAPR Update. Following the conclusions of the EGU and non-EGU multi-factor tests, the identified reductions for EGUs and non-EGUs are combined and collectively analyzed to assess their effects on downwind air quality and whether the rule achieves a full remedy to eliminate ''significant contribution'' while avoiding over-control.

To ensure that this rule implements a full remedy for the elimination of significant contribution from upwind states, the EPA has reviewed available information on all major industrial source sectors in the upwind states inclusive of commenter-provided data. This analysis leads the EPA to conclude that both EGUs and certain large sources in several specific industrial categories should be evaluated for emissions control opportunities. As discussed in the sections that follow, the EPA determines, for both EGUs and the selected non-EGU source categories, there are impactful emissions reduction opportunities available at reasonable cost-effectiveness thresholds. As in the Revised CSAPR Update, the EPA examines EGUs and non-EGUs in this section on consistent but distinct parallel tracks due to differences stemming from the unique characteristics of the power sector

[196] *See* CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

compared to other industrial source categories.

Since the NO_X SIP Call, EGUs have consistently been regulated under ozone transport rules. These units operate in a coordinated manner across a highly interconnected electrical grid. Their configuration and emissions control strategies are relatively homogenous, and their emissions levels and emissions control opportunities are generally very well understood due to longstanding monitoring and data-reporting requirements. Non-EGU sources, by contrast, are relatively heterogeneous, even within a single industrial category, and have far greater variation in existing emissions control requirements, emissions levels, and technologies to reduce emissions. In general, despite these differences, the information available for this rulemaking indicates that both EGUs and certain non-EGU categories have available cost-effective NO_X emissions reduction opportunities at relatively commensurate cost per ton levels, and these emissions reductions will make a meaningful improvement in air quality at the downwind receptors. Section V.B.2 of this document describes EPA's process for selecting specific non-EGU industries and emissions unit types included in this final rulemaking.

The EPA notes that its Step 3 analysis for this FIP does not assess additional emissions reduction opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing these emissions at the Federal level. EPA's various Federal mobile source programs, summarized in this section, have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions from final rules are factored into the Agency's assessment of air quality and contributions at Steps 1 and 2. Further, states are generally preempted from regulating new vehicles and engines with certain exceptions, and therefore a question exists regarding EPA's authority to address such emissions through such means when regulating in place of the states under CAA section 110(c). *See generally* CAA section 209. *See also* 86 FR 23099. As noted earlier, the EPA accounted for mobile source emissions reductions resulting from other federally enforceable regulatory programs in the development of emissions inventories used to support analysis for this final rulemaking, and the EPA does not evaluate any mobile source control measures in its Step 3 evaluation in this rule.[197] For further discussion of EPA's existing and ongoing mobile source measures, *see* section V.B.4 of this document.

B. Identifying Control Stringency Levels

1. EGU NO_X Mitigation Strategies

In identifying levels of uniform control stringency for EGUs, the EPA assessed the same NO_X emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available in this sector: (1) fully operating existing SCR, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing SNCRs, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; and (5) installing new SCRs. Finally, for each of these combustion and post combustion technologies identified, EPA evaluated whether emissions reduction potential from generation shifting at that representative dollar per ton level was appropriate at this Step. Shifting generation to lower NO_X emitting or zero-emitting EGUs may occur in response to economic factors. As the cost of emitting NO_X increases, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. For the reasons explained in the following sections and supported by technical information provided in the EGU NO_X Mitigation Strategies Final Rule TSD included in the docket for this final rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only EGU NO_X emissions controls 1 and 3 are possible for the 2023 ozone season (fully operating existing SCRs and SNCRs). The EPA finds that it is not possible to install state-of-the-art NO_X combustion controls by the 2023 ozone season on a regional scale; those controls are assumed to be available by the beginning of the 2024 ozone season. All cost values discussed in the rest of the section for EGUs are in 2016 dollars.

a. Optimizing Existing SCRs

Optimizing (*i.e.,* turning on idled or improving operation of partially operating) existing SCRs can substantially reduce EGU NO_X emissions quickly, using investments that have already been made in pollution control technologies. With the promulgation of the CSAPR Update and the Revised CSAPR Update, most operators in the covered states improved their SCR performance and have continued to maintain that level of improved operation. However, this optimized SCR performance was not universal and not always sustained. Between 2017 and 2020, as the CSAPR Update ozone-season NO_X allowance price declined, NO_X emissions rates at some SCR-controlled EGUs increased. For example, power sector data from 2019 revealed that, in some cases, operating units had SCR controls that had been idled or were operating partially, and therefore suggested that there remained emissions reduction potential through optimization.[198] The EPA determined in the Revised CSAPR Update that optimizing SCRs was a readily available approach for EGUs to reduce NO_X emissions in the 12 states addressed by a FIP in that rulemaking. Noticeable improvements in emissions rates at units with SCRs during the 2021 and 2022 compliance period further affirm the ability of sources to quickly implement this mitigation strategy and to realize emissions reductions from doing so. This emissions reduction measure is currently available at EGUs across the broader geography affected in this final rulemaking (including in states not previously affected by the Revised CSAPR Update). The EPA thus determines that SCR optimization, of both idled and partially operating controls, is a viable mitigation strategy for the 2023 ozone season.

The EPA estimates a representative marginal cost of optimizing SCR controls to be approximately $1,600 per ton, consistent with its estimation in the Revised CSAPR Update for this technology. EPA's EGU NO_X Mitigation Strategies Final Rule TSD for this rule describes a range of cost estimates for

[197] The EPA recognizes that mechanisms exist under title I of the CAA that allow for the regulation of the use and operation of mobile sources to reduce ozone-precursor emissions. These include specific requirements that apply in certain ozone nonattainment areas including motor vehicle inspection and maintenance (I/M) programs, gasoline vapor recovery, clean-fuel vehicle programs, transportation control programs, and vehicle miles traveled programs. *See, e.g.,* CAA sections 182(b)(3), 182(b)(4), 182(c)(3), 182(c)(4), 182(c)(5), 182(d)(1), 182(e)(3), and 182(e)(4). The EPA views these programs as well as others that meet CAA requirements can be effective and appropriate in the context of the planning requirements applicable to designated nonattainment areas.

[198] *See* ''Ozone Season Data 2018 vs. 2019'' and ''Coal-fired Characteristics and Controls'' at *https://www.epa.gov/airmarkets/power-plant-data-highlights#OzoneSeason.*

this technology noting that the costs are frequently lower than—and for the majority of EGUs, significantly lower than—this representative marginal cost. While the costs of optimizing existing, operational SCRs include only variable costs, the cost of optimizing SCR units that are currently idled considers both variable and fixed costs of returning the control into service. Variable and fixed costs include labor, maintenance and repair, parasitic load, and ammonia or urea for use as a NO_X reduction reagent in SCR systems. Depending on a unit's control operating status, the representative cost at the 90th percentile unit (among the relevant fleet of coal units with SCR covered in this rulemaking) ranges between $900 and $1,700 per ton. The EPA performed an in-depth cost assessment for all coal-fired units with SCRs and found that for the subset of SCRs that are already partially operating, the cost of optimizing is often much lower than $1,600 per ton and is often under $900 per ton. The EPA anticipates the vast majority of realized cost for compliance with this strategy to be better reflected by the $900 per ton end of that range (reflecting the 90th percentile of EGUs optimizing SCRs that are already partially operating) because this circumstance is considerably more common than EGUs that have ceased operating their SCR. This cost distinction is reflected in the EPA's RIA cost estimates. When representing the cost of optimization here, the EPA uses the higher value to reflect both optimization of partially operating and idled controls. EPA's analysis of this emissions control is informed by the latest engineering modeling equations used in EPA's IPM platform. These cost and performance equations were recently updated in the summer of 2021 in preparation for this rule, and subsequently evaluated for the final rule in 2022 and determined to still be appropriate. The description and development of the equations are documented in EGU NO_X Mitigation Strategies Final Rule TSD and accompanying documents.[199] They are also implemented in an interactive spreadsheet tool called the Retrofit Cost Analyzer and applied to all units in the fleet. These materials are available in the docket for this action.

The EPA is using the same methodology to identify SCR performance as it did in the Revised CSAPR Update. To estimate EGU NO_X reduction potential from optimizing, the EPA considers the difference between the non-optimized NO_X emissions rates and an achievable operating and optimized SCR NO_X emissions rate. To determine this rate, EPA evaluated nationwide coal-fired EGU NO_X ozone season emissions data from 2009 through 2019 and calculated an average NO_X ozone season emissions rate across the fleet of coal-fired EGUs with SCR for each of these eleven years. The EPA found it prudent to not consider the lowest or second-lowest ozone season NO_X emissions rates, which may reflect SCR systems that have all new components (*e.g.,* new layers of catalyst). Data from these systems are potentially not representative of ongoing achievable NO_X emissions rates considering broken-in components and routine maintenance schedules. Considering the emissions data over the full time period from 2009–2019 results in a third-best rate of 0.079 pounds NO_X per million British thermal units (lb/mmBtu). Therefore, consistent with the Revised CSAPR Update, where EPA identified 0.08 lb/mmBtu as a reasonable level of performance for units with optimized SCR, the EPA finalizes a rate of 0.08 lb/mmBtu as the optimized rate for this rule. The EPA notes that half of the SCR-controlled EGUs achieved a NO_X emissions rate of 0.064 lb/mmBtu or lower over their third-best entire ozone season. Moreover, for the SCR-controlled coal units that the EPA identified as having a 2021 emissions rate greater than 0.08 lb/mmBtu, the EPA verified that in prior years, the majority (more than 90 percent) of these same units had demonstrated and achieved a NO_X emissions rate of 0.08 lb/mmBtu or less on a seasonal or monthly basis. This further supports EPA's determination that 0.08 lb/mmBtu reflects a reasonable emissions rate for representing SCR optimization at coal steam units in identifying uniform control stringency. This emissions rate assumption of 0.08 lb/mmBtu reflects what those units would achieve on average when optimized, recognizing that individual units may achieve lower or higher rates based on unit-specific configuration and dispatch patterns. Units historically performing at, or better, than this rate of 0.08 lb/mmBtu are assumed to continue to operate at that prior performance level.

Given the magnitude and duration of the air quality problems addressed by this rulemaking, the EPA also applied the same methodology to identify a reasonable level of performance for optimizing existing SCRs at oil- and gas-fired steam units and simple cycle units (for which EPA determined that a 0.03 lb/mmBtu emissions rate reflected SCR optimization) as well as at combined-cycle units (for which the EPA determined that a 0.012 lb/mmBtu emissions rate reflected SCR optimization).

The EPA evaluated the feasibility of optimizing idled SCRs for the 2023 ozone season. Based on industry past practice, the EPA determined that idled controls can be restored to operation quickly (*i.e.,* in less than 2 months). This timeframe is informed by many electric utilities' previous long-standing practice of utilizing SCRs to reduce EGU NO_X emissions during the ozone season while putting the systems into protective lay-up during the non-ozone season months. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_X Budget Trading Program. It was quite typical for SCRs to be turned off following the end of the ozone season control period on September 30. These controls would then be put into protective lay-up for several months of non-use before being returned to operation by May 1 of the following ozone season.[200] Therefore, the EPA believes that optimization of existing SCRs is possible for the portion of the 2023 ozone season covered under this final rule. The recent successful implementation of this strategy for the Revised CSAPR Update Rule, and corresponding fast improvement in SCR performance rates at units with optimization potential, provides further supporting evidence of the viability of this timeframe.

The vast majority of SCR-controlled units (nationwide and in the 23 linked states for which EPA is issuing a FIP for EGUs) are already partially operating these controls during the ozone season based on reported 2021 and 2022 emissions rates. Notably, the higher ozone season NO_X allowance price observed in 2022 resulted in more units operating their controls closer to their potential and bringing collective emissions from those 12 states closer to the 2023 emissions budgets for those states in this final rule, accordingly.

[199] The CSAPR Update estimated $1,400 per ton as a representative cost of turning on idled SCR controls. EPA used the same costing methodology while updating for input cost increases (*e.g.,* urea reagent) to arrive at $1,600 per ton in the final Revised CSAPR Update (while also updating from 2011 dollars to 2016 dollars).

[200] In the 22-state CSAPR Update region, 2005 EGU NO_X emissions data suggest that 125 EGUs operated SCR systems in the summer ozone season while idling these controls for the remaining 7 non-ozone season months of the year. Units with SCR were identified as those with 2005 ozone season average NO_X rates that were less than 0.12 lb/mmBtu and 2005 average non-ozone season NO_X emissions rates that exceeded 0.12 lb/mmBtu and where the average non-ozone season NO_X rate was more than double the ozone season rate.

Existing SCRs operating at partial capacity still provide functioning, maintained systems that may only require an increased chemical reagent feed rate (*i.e.,* ammonia or urea) up to their design potential and catalyst maintenance for mitigating NO_X emissions; such units may require increased frequency or quantity of deliveries, which can be accomplished within a few weeks. In many cases, EGUs with SCR have historically achieved more efficient NO_X removal rates than their current performance and can therefore simply revert to earlier operation and maintenance plans that achieved demonstrably better SCR performance.

In the 12 states subject to this control stringency in the Revised CSAPR Update, the EPA observed significant immediate-term improvements in SCR performance in the first ozone season following finalization of that rule, as evidenced in particular by the sharp drop in emissions rate at Miami Fort unit 7 (*see* EGU NO_X Mitigation Strategies Final Rule TSD). For instance, in June of 2021—within months of the Revised CSAPR Rule being finalized—Miami Fort Unit 7 and Unit 8 (which had substantial SCR optimization potential) were able to reach levels of 0.07 lb/mmBtu of NO_X (a greater than 50 percent reduction from where they had operated the prior year during the same month). Such empirical data further illustrates the viability of this mitigation strategy for the 2023 control period in response to this rule.

Comment: EPA received comments supporting the 0.08 lb/mmBtu emissions rate as achievable and, according to some commenters, underestimate the control's potential. Some of these commenters went on to provide their own analysis demonstrating that the 0.08 lb/mmBtu was achievable not only on average for the non-optimized fleet, but also for these individual units and that the resulting state emissions budgets were likewise achievable. Some commenters suggested that the rate should be lower and premised on EPA using the first- or second-best year instead of the third best year of SCR performance. Some commenters observed that using the same methodology, but omitting SCR units that have since retired, could deliver an even lower SCR performance benchmark rate.

Response: The EPA notes that updating the inventory of coal-fired EGUs to reflect recent retirements and to include data reported since 2019 (*e.g.,* 2009–2021) would provide a lower value of 0.071 lb/mmBtu. However, EPA acknowledges that 2020 operational data included impacts from COVID–19 pandemic shutdowns (such as atypical electricity demand patterns) which complicate interpretations of typical EGU emissions performance. Additionally, EPA believes that in this context, a unit's retirement in 2020 or 2021 does not obviate the usefulness of its prior SCR operational data for assessing the emissions control performance of other existing SCRs across the fleet. Consequently, EPA is continuing to use the same value of the 0.08 lb/mmBtu emissions rate calculated from the 2009–2019 data set identified at the time of the final Revised CSAPR Update Rule in this rulemaking. EPA's analysis focuses on the third best ozone season average rate because EPA believes that the first- or second-best rate, consistent with its CSAPR Update final rule and in the Revised CSAPR Update, could give undue weight to the emissions control performance of new SCRs in their first year of service and their corresponding newer SCR components. It does not necessarily reflect achievable ongoing NO_X emissions rates at relatively older SCRs. The third-lowest season was selected because it represents a time when the unit was most likely consistently and efficiently operating its SCR in a manner representative of sustained future operation.

Comment: Other commenters suggested that EPA should apply a higher NO_X emissions rate than 0.08 lb/mmBtu to existing SCR at coal EGUs premised on considerations such as: a generally reduced average capacity factor for coal units in recent years, the age of the boiler, coal rank (bituminous or subbituminous), or other unit-specific considerations that commenters claim make the 0.08 lb/mmBtu rate unattainable for a specific unit.

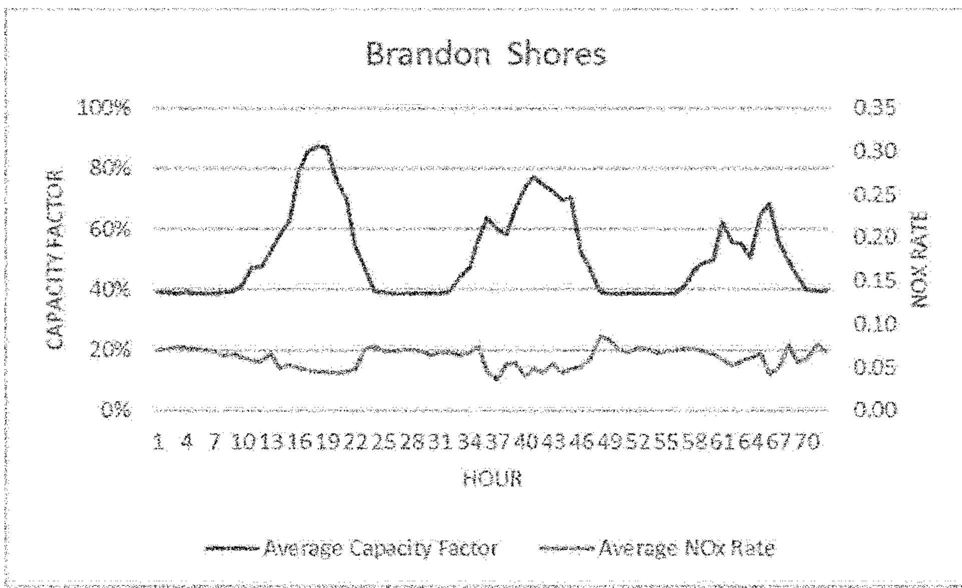
Response: EPA did not find sufficient justification to apply a higher average emissions rate than 0.08 lb/mmBtu. EPA found that some commenters were misunderstanding or misconstruing both EPA's assumption and implementation mechanism as a unit-level requirement for every SCR-controlled unit instead of a reflection of a fleet-wide average based on a third-best rate. The commenters' observation—that 0.08 lb/mmBtu may be difficult for some units to achieve or may not be a preferred compliance strategy for a given unit given its dispatch levels—does not contradict EPA's assumption, but rather supports its methodology and assumptions. As EPA pointed out in the proposed rule, this fleet-level emissions rate assumption of 0.08 lb/mmBtu for non-optimized units reflects, on average, what those units would achieve when optimized. Some of these units may achieve rates that are lower than 0.08 lb/mmBtu, and some units may operate above that rate based on unit-specific configuration and dispatch patterns. In other words, EPA is using this assumption as the average performance of a unit that optimizes its SCR, recognizing that heterogeneity within the fleet will likely lead some units to overperform and others to underperform this rate. Moreover, a review of unit-specific historical data indicates that this is a reasonable assumption: not only has the group of units with SCR optimization potential demonstrated they can perform at or better than the 0.08 lb/mmBtu rate on average, over 90 percent of the individual units in this group have already met this rate on a seasonal and/or monthly basis based on their reported historical data.

Additionally, EPA's examination of units experiencing SCR performance deterioration included notable instances of poor NO_X control at *increased* capacity factors. As an example, Miami Fort Unit 7 had considerably more hours of operation at a 70 to 79 percent capacity factor in 2019 compared to previous years. However, Miami Fort Unit 7's ozone-season NO_X emissions rate *substantially increased* in 2019 compared to previous years. This SCR performance deterioration runs counter to the notion that an increase in emissions rates is purely driven by reduced capacity factor, as suggested by commenters. This substantial deterioration in the median emissions rate performance is observable even when comparing specific hours in 2019 to specific hours in prior years when the unit operated in the same 70 to 79 percent capacity factor range. In fact, in 2019 the unit experienced notable emissions rate increases from prior years across multiple capacity factor ranges as low as 40 percent to as high as 80 percent. This type of data indicates instances where the increase in emissions rate (and emissions) is not necessitated by load changes but is more likely due to the erosion of the existing incentive to optimize controls (*i.e.,* the ozone-season NO_X allowance price has fallen so low that unit operators find it more economic to surrender additional allowances instead of continuing to operate pollution controls at an optimized level).

EPA observed this pattern in other units identified in this rulemaking as having significant SCR optimization emissions reduction potential. In the accompanying Emissions Data TSD for the supplemental notice that EPA recently released in a proceeding to address a recommendation submitted to EPA by the Ozone Transport Commission under CAA section 184(c), EPA noted, ''In their years with the lowest average ozone season NO_X emissions rates in this analysis, these EGUs had relatively low NO_X emissions rates at mid- and high-operating levels; moreover, there was little variability in NO_X emissions rates at these operating levels. However, during the 2019 ozone season, these EGUs had higher NO_X emissions rates and greater variability in NO_X emissions rates across operating levels than in the past, particularly at mid-operating levels.'' [201] That hourly data analysis, included in this docket, controls for operating level changes and still finds there to be instances across multiple SCR-controlled units where hourly emissions rates are increasing even when compared to the same load levels in previous years.

Some commenters have alleged that in recent years coal-fired EGUs have declined in capacity factor and that SCR performance declines at those lower operating levels. However, hourly data indicate that maintaining consistent SCR performance at lower capacity factors is possible. For example, the unit-level performance data in Figure 2 to section VI.B of this document show the emissions rate at a coal-fired EGU with existing SCR staying relatively low (consistent with our optimization assumption of 0.08 lb/mmBtu) and stable across a wide range of capacity factors.[202]

Figure 2 to section V.B.1.a: Example of Consistently Low Unit-level Emissions Rate During Periods of Varying Capacity Factor



Furthermore, most recent data from 2022 illustrates that cycling units do have the ability to adjust cycling patterns in a manner that enables them to maintain a lower emissions rate throughout the season while still achieving a load cycling pattern at the unit. For example, the SCR-controlled Conemaugh Unit 2 in Pennsylvania adjusted operating patterns in 2022 to have a slightly higher minimum load in most hours (maintaining a range of 550 MW–900 MW for most hours as opposed to 450 MW–900 MW observed in 2021). This change in minimum load, and corresponding minimum operating temperature, enabled the unit to maintain emissions rates in the 0.05 lb/mmBtu to 0.10 lb/mmBtu range for most of the 2022 season (as opposed to NO_X emissions rates that regularly exceeded 0.25 lb/mmBtu in the 2021 season). This 2022 improvement in SCR operation occurred during a period when allowance prices increased relative to prior years, creating an incentive for potential emissions reductions through SCR optimization.

Comment: EPA also received comment suggesting it should deviate from its approach in the CSAPR Update of using a nationwide data set of all SCR controlled coal units to establish a third best year, and instead limit the dataset to either just the covered states, or—in the case of some commenters—just to the baseline years of those units at which EPA is identifying optimization potential. They claim the current methodology may capture extremely efficient SCR performance years at the best performing units and that level of performance may not be available at all units with optimization potential. These commenters also disagree with the EPA finding that SCRs can consistently maintain a 0.08 lb/mmBtu rate over time.

Response: EPA reviewed the data and its methodology and evaluated it against its intention to identify a technology-specific representative emissions rate for SCR optimization. In doing so, EPA did not identify any need to make the suggested change. EPA is interested in the performance potential of a technology, and a larger dataset provides a superior indication of that potential as opposed to a smaller, state-limited dataset. Moreover, EPA's use of the third best year (as opposed to best) from its baseline period results in an average optimization level that is robust

[201] ''Analysis of Ozone Season NO_X Emissions Data for Coal-Fired EGUs in Four Mid-Atlantic States,'' EPA Clean Air Markets Division. December 2020. Available at *https://www.epa.gov/sites/production/files/2020-12/documents/184c_emission_data_tsd.pdf.*

[202] EPA, *Air Markets Program Data.* Available at *www.epa.gov/ampd.*

to the commenters' concern that EPA should not overstate the fleetwide representative optimization level. Prior experience with EPA's methodology and program has borne out empirical evidence of its reasonableness. In both the CSAPR Update and in Revised CSAPR Update rule, EPA appropriately relied on the largest dataset possible (*i.e.,* nationwide) to derive technology performance averages that it then applied respectively to the CSAPR Update 22-state region and the Revised CSAPR Update's 12-state region. EPA repeats that successful approach in this rule. Finally, as noted in the preceding paragraphs, in affirming the reasonableness of this approach, EPA examined the historical reported data (pre-2021) for the units in the states with SCR optimization potential and found the nationwide derived average appropriate and consistent with demonstrated capability and performance of units within those states. That is, the vast majority of units to which this resulting emissions rate assumption was being applied had demonstrated the ability to achieve this rate in some prior year for an extended monthly or seasonal basis. This information is discussed further in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket.

Comment: Some commenters suggested the price of SCR optimization is higher than the $1,600 per ton figure proposed due to current market conditions for aqueous ammonia or other input prices.

Response: EPA provides a representative cost for this mitigation technology which is anticipated to reflect the cost, on average, throughout the compliance period for the rule. While there may be volatility in the market during that period where the price falls above or below the single representative threshold value, EPA's EGU NO_X Mitigation Strategies Final Rule TSD explains how the representative cost is derived and is inclusive of consultation and vetting by third party air pollution control consulting groups. Commenters did not demonstrate that observed 2021 elevated prices amid market volatility would continue into the future compliance periods discussed in this rule. Moreover, the selection of the mitigation technology is reflective of a variety of factors including reduction potential and air quality impact. A higher cost (commenter suggests up to $3,800 per ton) would not change EPA's determination that optimizing already existing SCRs is an appropriate mitigation strategy for Step 3 emissions reduction analysis in this rulemaking as it would remain one of the most widely available, widely practiced, and lowest cost mitigation measures with meaningful downwind air quality benefit. Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD further addresses commenters' concerns as it provides a variety of sensitivities showing cost per ton levels under a variety of different input assumptions (including higher material and reagent cost). It supports the continued inclusion of this technology in the rule even in the event that higher reagent costs extend into compliance years.

Comment: While many commenters supported the feasibility of 2023 ozone-season implementation by noting the ''immediate availability'' of SCR optimization, other commenters argued that the engineering, procurement, and other steps required for SCR optimization were not feasible given the anticipated limited window between rule finalization and the start of the 2023 ozone season.

Response: There is ample evidence of units restoring their optimal performance within a two-month timeframe. Not only do units reactivate SCR performance level at the start of an ozone-season when tighter emissions limits begin, but unit-level data also shows instances where sources have demonstrated the ability to quickly alter their emissions rate within an ozone-season and even within the same day in some cases. Moreover, this emissions control is familiar to sources and was analyzed and included in the Revised CSAPR Update emissions budgets finalized in 2021 and the CSAPR Update emissions budgets finalized in 2016. With this experience, and notice through the March 2022 proposed rule, as well as over two months from final rule to effective date, the viability of this emissions control for the 2023 ozone season is consistent with the 2-week to 2-month timeframe that EPA identified as reasonable in the CSAPR Update, Revised CSAPR Update, and in this rulemaking. Similar to prior rules, commenters provide some unit-level examples where it has taken longer. Also similar to those prior rules, EPA does not find those unit-level examples compelling in the context of its fleet average assumptions and in the implementation context of a trading program which provides compliance alternatives in the event a specific unit prefers more time to implement a given control measure. As noted in *Wisconsin,* ''. . . all those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.'' 938 F.3d at 330.

b. Installing State-of-the-Art NO_X Combustion Controls

The EPA estimates that the representative cost of installing state-of-the-art combustion controls is comparable to, if not notably less than, the estimated cost of optimizing existing SCR (represented by $1,600 per ton). State-of-the-art combustion controls such as low-NO_X burners (LNB) and over-fire air (OFA) can be installed or updated quickly and can substantially reduce EGU NO_X emissions. Nationwide, approximately 99 percent of coal-fired EGU capacity greater than 25 MW is equipped with some form of combustion control; however, the control configuration or corresponding emissions rates at a small portion of those units (including units in those states covered in this action) indicate they do not currently have state-of-the-art combustion control technology. For this rulemaking, the Agency re-evaluated its NO_X emissions rate assumptions for upgrading existing combustion controls to state-of-the-art combustion control. The EPA is maintaining its determination that NO_X emissions rates of 0.146 to 0.199 lb/mmBtu can be achieved on average depending on the unit's boiler configuration,[203] and, once installed, reduce NO_X emissions at all times of EGU operation.

These assumptions are consistent with the Revised CSAPR Update. They are further discussed in the EGU NO_X Mitigation Strategies Final Rule TSD. In particular, the EPA is finalizing, as proposed, the application of the 0.199 lb/mmBtu emissions rate assumption for both boiler types (tangentially and wall fired). EPA's analysis calculated average emissions rates of 0.199 lb/mmBtu for combustion controls on dry bottom wall fired units and 0.146 lb/mmBtu for tangentially fired units. However, many of the likely impacted units burn bituminous coal, and the 0.146 lb/mmBtu nationwide average for tangentially-fired (inclusive of subbituminous units) appears to be below the demonstrated emissions rate of state-of-the-art combustion controls for bituminous coal units of this boiler type. Therefore, EPA's assignment of a 0.199 lb/mmBtu emissions rate for combustion controls at all affected unit types is robust to current and future coal choice at a unit.

The EPA has previously examined the feasibility of installing combustion controls and found that industry had demonstrated ability to install state-of-

[203] Details of EPA's assessment of state-of-the-art NO_X combustion controls are provided in the EGU NO_X Mitigation Strategies Final Rule TSD.

the-art LNB controls on a large unit (800 MW) in under six months when including the pre-installation phases (design, order placement, fabrication, and delivery).[204] In prior rules, the EPA has documented its own assessment of combustion control timing installation as well as evaluated comments it received regarding installation of combustion controls from the Institute of Clean Air Companies.[205] Those comments provided information on the equipment and typical installation time frame for new combustion controls, accounting for all steps. To date, EPA has found it generally takes between 6–8 months on a typical boiler—covering the time through bid evaluation through start-up of the technology. The deployment schedule is repeated here as:

- 4–8 weeks—bid evaluation and negotiation
- 4–6 weeks—engineering and completion of engineering drawings
- 2 weeks—drawing review and approval from user
- 10–12 weeks—fabrication of equipment and shipping to end user site
- 2–3 weeks—installation at end user site
- 1 week—commissioning and start-up of technology

Given the referenced timeframe of approximately 6 to 8 months to complete combustion control installation in the region, the EPA is finalizing that installation of state-of-the-art combustion controls is a readily available approach for EGUs to reduce NO_X emissions by the start of the 2024 ozone season. More details on these analyses can be found in the *EGU NO_X Mitigation Strategies Final Rule TSD*.

The cost of installing state-of-the-art combustion controls per ton of NO_X reduced is dependent on the combustion control type and unit type. The EPA estimates the cost per ton of state-of-the-art combustion controls to be $400 per ton to $1,200 per ton of NO_X removed using a representative capacity factor of 85 percent. This cost fits well within EPA's representative cost threshold observed for SCR optimization and combustion controls (of $1,600 per ton) which would accommodate combustion control upgrade even under scenarios where a lower capacity factor is assumed. 99 percent of units have some form of combustion controls, indicating the widespread cost-effectiveness of this control. *See* the *EGU NO_X Mitigation Strategies Final Rule TSD* for additional details.

At proposal EPA assumed that emissions reductions from combustion control upgrades at affected EGUs in states subject to the Revised CSAPR Update program could occur by 2023 given that those EGUs may have already begun pursuing such upgrades in response to that previous rule. However, EPA does not have data to confirm that presumption, and hence EPA is determining in this final rule that combustion control upgrades for all affected EGUs, regardless of whether they were previously subject to the Revised CSAPR Update program, should be considered available by the 2024 ozone season, consistent with the deployment schedule noted in this section.

Comment: Some commenters suggested that EPA, in its modeling for the proposed rule, overestimated the ability of combustion control technologies to achieve very low NO_X emissions rates. The commenters claim EPA's assumptions are derived from projected NO_X emissions rates based on ideal circumstances for NO_X emissions reductions, including combinations of fuel composition and unit design that are not typical and should not be extrapolated to the national inventory.

Response: EPA's emissions performance rate for state-of-the-art combustion controls is derived from historical data and takes both boiler type and coal choice into account. EPA reviewed historical data and identified the average emissions rates for units with this technology already in place. It segmented this analysis by boiler type (dry-bottom wall-fired boiler and tangentially-fired, and further segmented by coal rank to assess the average performance among these varying parameters. As explained in the *EGU NO_X Mitigation Strategies Final Rule TSD,* EPA chose an emissions rate for which it verified accommodated (*i.e.,* was greater than or equal to) the average performance rate identified above for each boiler configuration with state-of-the-art combustion controls and resulted in reductions consistent with the technology's assumed percent reduction potential when applied to this subset of units. It also assessed whether the rate had been demonstrated by both subbituminous and bituminous coal units with state-of-the-art combustion controls. EPA further assessed the percent reduction that achieving this rate would require from the specific segment of the fleet identified as having this mitigation measure available. Here too, EPA found that the effective percent reduction for the identified fleet (inclusive of their existing coal rank choice) is well within the historical performance range for this technology. Therefore, EPA is finalizing the combustion control upgrade performance assumption of 0.199 lb/mmBtu as appropriate representative average performance rate for this technology and robust to different boiler types and coal ranks.

c. Optimizing Already Operating SNCRs or Turning on Idled Existing SNCRs

Optimizing already operating SNCRs or turning on idled existing SNCRs can also reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. Compared to no post-combustion controls on a unit, SNCRs can achieve a 25 percent reduction on average in EGU NO_X emissions (with sufficient reagent). They are less capital intensive but less efficient at NO_X removal than SCRs. These controls are in use to some degree across the U.S. power sector. In the 22 linked states with EGU reductions identified in this final rule, approximately 11 percent of coal-fired EGU capacity is equipped with SNCR.[206] Recent power sector data suggest that, in some cases, SNCR controls have been operating less in 2021 relative to performance in prior years. For instance, EPA reviewed the last five years of performance data for all the units with SNCR optimization potential in its Engineering Analysis. It found that in 2021—the most recent year reviewed—that the weighted average ozone season emissions rate for these units was higher than the prior three years (indicating some deterioration in average performance). Moreover, a unit level review illustrated that 80 of the 107 units had performed better in a prior year by an average of 13 percent—indicating substantial optimization potential.[207]

The EPA determined that optimizing already operating SNCRs or turning on idled SNCRs is an available approach for EGUs to reduce NO_X emissions, has similar implementation timing to restarting idled SCR controls (less than 2 months for a given unit), and therefore could be implemented in time for the 2023 ozone season. In this final rule, the EPA is determining that this emissions

[204] The EPA finds that, generally, the installation phase of state-of-the-art combustion control upgrades—on a single-unit basis—can be as little as 4 weeks to install with a scheduled outage (not including the pre-installation phases such as permitting, design, order, fabrication, and delivery) and as little as 6 months considering all implementation phases.

[205] EPA–HQ–OAR–2015–0500–0093.

[206] *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6*.

[207] See ''Historical Emission Rates for Units with SNCR Optimization Potential'' in the docket for this rulemaking.

control measure is available beginning in the 2023 ozone season.

Using the Retrofit Cost Analyzer described in the *EGU NO_X Mitigation Strategies Final TSD,* the EPA estimates a representative cost of optimizing SNCR ranging from approximately $1,800 per ton (for partially operating SNCRs) to $3,900 per ton (for idled SNCRs). For existing SNCRs that have been idled, unit operators may need to restart payment of some fixed and variable operating costs including labor, maintenance and repair, parasitic load, and ammonia or urea. The EPA determined that the majority of units with existing SNCR optimization potential were already partially operating their controls. Therefore, the EPA finalizes a representative cost of $1,800 per ton for SNCR optimization as this value best reflects the circumstances of the majority of the affected EGUs with SNCR.

d. Installing New SNCRs

The EPA evaluated potential emissions reductions and associated costs from retrofitting EGUs with new SNCR post-combustion controls at steam units lacking such controls, which can achieve a 25 percent NO_X reduction on average. New SNCR technology provides owners with a relatively less capital-intensive option for reducing NO_X emissions compared to new SCR technology, albeit at the expense of higher operating costs on a per-ton basis and less total emissions reduction potential. SNCR is more widely observed on relatively smaller coal units given its low capital/variable cost ratio. The average capacity of a coal unit with SNCR is half the size of the average capacity of coal unit with SCR.[208] Given these observations, the EPA identifies this technology as an emissions reduction measure for coal units less than 100 MW lacking post-combustion NO_X control technology. As described in the *EGU NO_X Mitigation Strategies Final Rule TSD,* the EPA estimated that $6,700 per ton reflects a representative SNCR retrofit cost level for these units.

For this rulemaking, EPA is not considering SNCR installation timing unto itself but is instead considering how long eligible EGUs may need to adopt either SNCR or SCR as a post-combustion control measure. SNCR installations generally have shorter project installation timeframes relative to other post-combustion controls. The time for engineering review, contract award, fabrication, delivery, and hookup is as little as 16 months including pre-contract award steps for an individual power plant installing controls on more than one boiler. However, SNCR retrofits have less pollution reduction potential than SCRs, and as explained further in the next section, the EPA is identifying the retrofit of new SCR rather than SNCR as a strategy for larger steam units due to this lower removal efficiency. This approach respects empirical evidence that larger coal-fired EGUs which installed post-combustion NO_X control technology have overwhelmingly chosen SCRs over SNCRs. Even for smaller units less than 100 MW identified as potential candidates for SNCR technology, the EPA does not want to preclude those units from pursuing SCR in lieu of SNCR.

Therefore, in this final rule the EPA defines the availability of emissions reductions from post-combustion control installation to be in 2026, the same period as the start of SCR-based reductions becoming available, to allow enough time for eligible EGUs to choose between SCR or SNCR. SNCR installation shares similar implementation steps with and also need to account for the same regional factors as SCR installations, which are described in the next section. While the EPA is determining that at least 16 months would be needed to complete all necessary steps of SNCR development and installation, an eligible EGU choosing new SCR instead would require installation timing of 36 to 48 months. EPA believes its finalized joint timing considerations for post-combustion control retrofits (SNCR and SCR) are justified given that post-combustion control retrofit decisions are subject to unit-specific economic and engineering factors and are sensitive to operator compliance strategy choices with respect to multiple regulatory requirements.

Comment: Some commenters argued that post-combustion control timing assumptions (SCR and SNCR) should be decoupled, which could result in the EPA using the 16-month time frame specific to SNCR installation to require emissions reductions related to new SNCR installations by the 2025 ozone season.

Response: The EPA does not agree that decoupling SCR and SNCR timing consideration is justified in the context of this final rule's emissions control program for EGUs. Approximately 1,000 tons of emissions reduction potential are estimated for the small coal EGUs deemed eligible for SNCR retrofit. The incentives provided through the implementation of this rule's trading program will encourage these EGUs to determine and adopt emissions reduction measures (including SNCR or SCR) as soon as possible to reduce their allowance holding compliance burden. By scheduling SNCR-related emissions reductions potential for the 2026 ozone season, the EPA preserves the opportunity for considerably superior emissions reduction potential from these EGUs should they select SCR retrofit instead, while still requiring post-combustion control emissions reduction potential ahead of the next attainment date.

Comment: Some commenters argued that the upper range of SNCR NO_X removal performance (40 percent) referenced by EPA is optimistic for many boilers.

Response: EPA evaluated both actual performance and engineering literature regarding SNCR retrofit technology and found both sources supported the range of reduction estimates cited by EPA. (Refer to the *EGU NO_X Mitigation Strategies Final Rule TSD* in the docket for this rulemaking for additional information.) Moreover, for purposes of calculating state budgets, EPA assumes 25 percent reduction from this technology—not 40 percent—which reflects a value well within the range of documented performance for this technology. Remaining comments on SNCR performance potential are addressed in the *RTC* Document and in the *EGU NO_X Mitigation Strategies Final Rule TSD.*

e. Installing New SCRs

Selective Catalytic Reduction (SCR) controls already exist on over 66 percent of the coal fleet in the linked states that are subject to a FIP in this rulemaking. Nearly every pulverized coal unit larger than 100 MW built in the last 30 years has installed this control, which is generally required for Best Available Control Technology (BACT) purposes. Other than circulating fluidized bed coal units which can achieve a comparably low emissions rate without this technology, the EPA identifies this emissions reduction measure for coal steam units greater than or equal to 100 MW. SCR is widely available for existing coal units of this size and can provide significant emissions reduction potential, with removal efficiencies of up to 90 percent. The EPA limited its consideration of SCR technology to steam units greater than or equal to 100 MW. The costs for retrofitting a plant smaller than 100 MW with SCR increase

[208] *See* EGU NO_X Mitigation Strategies Final Rule TSD for additional discussion.

rapidly due to a lack of economies of scale.[209]

The amount of time needed to retrofit an EGU with new SCR extends beyond the 2023 ozone season. Similar to the SNCR retrofits discussed in this section, the EPA evaluated potential emissions reductions and associated costs from this control technology, as well as the impacts and need for this emissions control strategy, at the earliest point in time when their installation could be achieved. EPA notes that it has previously determined in the context of ozone transport that regional scale implementation of SCRs at numerous EGUs is achievable in 36 months. *See* 63 FR 57356, 57447–50 (October. 27, 1998). However, since that time, the EPA has found up to 36–48 months to be a more appropriate installation timeframe for regionwide actions when the EPA is evaluating multiple installations at multiple locations.[210]

In the past, the EPA has found the amount of time to retrofit a single EGU with new SCR, depending on the regulatory program under which such control may be required, may vary between approximately 2 and 4 years depending on site-specific engineering considerations and on the number of installations being considered. This includes steps for engineering review, construction permit, operating permit, and control technology installation (including fabrication, pre hookup, control hookup, and testing). EPA's assessment of installation procedures suggests as little as 21 months may be needed for a single SCR at an individual plant and 36 months at a single plant with multiple boilers. EPA's assessment of units with SCR retrofit potential indicate the majority fall into this first classification, *i.e.,* a single SCR at a power plant.

While EPA finds that 36 months is a possible time frame for SCR installation at individual units or plants, the total of nearly 31 GW of coal capacity with SCR retrofit potential and 19 GW of oil/gas steam capacity with SCR retrofit potential within the geographic footprint of the final rule is a scale of retrofit activity that is not demonstrated to have been achieved within a three-year span based on data from the past two decades. Given that some of the assumed SCR retrofit potential occurs at plants with multiple units identified with retrofit potential, and given the total volume of SCR retrofit capacity being implemented across the region, EPA is allowing in this final rule between 36 to 48 months, consistent with the regional time frame discussed for SCR retrofit in prior rules, for the full implementation of reductions commensurate with this volume of SCR retrofit capacity, as described further in section VI.A of this document.

The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NO_X rates of 0.05 lb/mmBtu or less. These updates are further discussed in the EGU NO_X Mitigation Strategies Final Rule TSD.[211] Based on the characteristics of coal units of 100 MW or greater capacity that do not have post-combustion

NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $11,000 per ton.[212]

The 0.05 lb/mmBtu emissions rate performance assumption for new SCR retrofits is supported by historical data and third party independent review by pollution control engineering and consulting firms. The EPA first examined unit-level emissions rate data for coal-fired units that had a relatively recent SCR installation (within the last 10 years). The best performing 10 percent of these SCRs were demonstrating seasonal emissions rates of 0.036 lb/mmBtu during this time.

While the EPA identified the 0.05 lb/mmBtu performance assumption consistent with historical data, these performance levels are also informed and consistent with the Agency's IPM modeling assumptions used for more than a decade. These modeling assumptions are based on input from leading engineering and pollution control consulting entities. Most recently, these data assumptions were affirmed and updated in the summer of 2021 and included in the docket for this rulemaking.[213] The EPA relies on a global firm providing engineering, construction management, and consulting services for power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Their familiarity with state-of-the art pollution controls at power plants derives from experience providing comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance. This review and update supported the 0.05 lb/mmBtu performance assumption as a representative emissions rate for new SCR across coal types.

The EPA performed an assessment for oil/gas steam units in which it evaluated the nationwide performance of those units with SCR technology. For these units, the EPA tabulated EGU NO_X ozone season emissions data from 2009 through 2021 and calculated an average NO_X ozone season emissions rate across the fleet of oil- and gas-fired EGUs with SCR for each of these years. The EPA identified the third lowest year which yielded an SCR performance rate of 0.03 lb/mmBtu as representative of performance for this retrofit technology applied to this type of EGU. Next, the EPA evaluated the emissions and operational characteristics for the existing oil/gas steam fleet lacking SCR technology. EPA's analysis indicated that the majority of reduction potential (approximately 76 percent) from these units occurred at units greater than or equal to 100 MW and that were emitting more than 150 tons per ozone season (*i.e.,* approximately 1 ton per day). Moreover, the cost of reductions for units falling below these criteria increased significantly on a dollar per ton basis. Therefore, the EPA identified the portion of the oil/gas steam fleet meeting these criteria (*i.e.,* greater than or equal to 100 MW and emitting more than 150 tons per ozone season) as representative of the SCR retrofit reduction potential.[214] For this segment of the oil/gas steam units lacking post-combustion NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $7,700 per ton.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of SCR installation occurring in

[209] IPM Model-Updates to Cost and Performance for APC Technologies. SCR Cost Development Methodology for Coal-fired Boilers. February 2022.

[210] *See, e.g.,* CSAPR Close-Out, 83 FR 65878, 65895 (December 21, 2018) and Revised CSAPR Update, 86 FR 23102 (April 30, 2021). *See also* Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073 (Oct. 2002), available at *https://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf*.

[211] As noted in that TSD, approximately half of the recent SCR retrofits (*i.e.,* installed in the last 10 years) have demonstrated an emission rate across the ozone season below 0.05 lb/mmBtu, even absent a requirement or strong incentive to operate at that level in many cases.

[212] This cost estimate is representative of coal units lacking any post-combustion control. A subset of units within the universe of coal sources with SCR retrofit potential, but that have an existing SNCR technology in place would have a weighted average cost that falls above this level, but still cost effective. See the EGU NO_X Mitigation Strategies Final Rule TSD for more discussion.

[213] See ''IPM Model—Updates to Cost and Performance for APC Technologies: SCR Cost Development Methodology for Coal-fired Boilers''.

[214] The EPA used a 3-year average of 2019–2021 reported ozone season emissions to derive a tons per ozone season value representative for each covered oil/gas steam unit.

a limited region of the country would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that achieving such a timeframe against a backdrop of such challenging circumstances is unprecedented and that EPA's assumptions ignore that many of the remaining unretrofitted coal units reflect more site-specific challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA reviewed the comments and is making several changes in this final rule to address some of the concerns identified by the commenters. In particular, EPA found that its own review of historical retrofit patterns as well as technical information submitted by commenters supported commenters' concerns regarding: (1) current and anticipated constraints in labor and supply markets, (2) the potential collective capacity levels of SCR retrofit within 36 months, and (3) possible site-specific complexities at the remaining units without an existing SCR. To address these concerns, EPA is phasing in its SCR installation requirement over a 48-month time frame in this final rule, instead of a 36-month time frame as proposed (see additional detail and discussion in section VI.A.2.a and the EGU NO_X Mitigation Strategies Final Rule TSD). EPA will require half of the reductions associated with SCR installation in 2026 and the other half in 2027. Additionally, EPA is moving the daily backstop rate for these units with identified SCR reduction potential from 2027 to no later than 2030, which defers the increased allowance surrender ratio for emissions above the backstop rate at any outlier units unable to complete the retrofit during that time frame. These adjustments continue to incentivize reductions in NO_X emissions by the attainment date that are consistent with cost-effective SCR controls, but provide more flexibility (both from timing and technology perspective) in how they are procured.

Some commenters requested more than 48 months to install SCR controls based on the collective total volume of SCR retrofit volume identified and past projects that took five or more years. EPA disagrees with these comments and finds that they ignored key aspects of the proposed rule. First, the final rule does not directly require implementation of SCR; rather, it requires reductions commensurate with SCR installations based on a rigorous assessment of SCR retrofit potential. Implementing the reductions through a trading program means that sources in many cases, as suggested by the *Regulatory Impact Analysis (RIA),* will find alternative, and more economic means, of reducing emissions—including reduced generation and retirements that are already planned based on the age of the unit, decarbonization goals, or compliance with other Federal/state/local regulation compliance dates. Moreover, the additional new generation incentives provided by the Inflation Reduction Act (enacted after the proposed rule) will further increase the pace of new generation replacing some of the older generating capacity identified as having retrofit potential.[215] In short, although EPA identified the total SCR retrofit capacity potential for today's existing fleet and does not premise any reduction requirements of incremental retirements, the announced and planned futures for these units indicates that many will likely retire instead of installing SCR. For the capacity identified at Step 3 which lacks SCR, the planned or projected retirement in place of a retrofit moots the SCR timing for these units. Moreover, it also reduces the demand for associated labor and materials which, in turn, frees up resources for any units proceeding with a SCR retrofit. Therefore, comments which cite labor and supply chain challenges for accommodating the entire fleet capacity identified as having SCR retrofit potential significantly overstate the supply-side challenge—as it ignores the fact that much of this capacity has explicit or expected operation plans that will result in compliance without a retrofit.

Even for sources choosing a SCR retrofit compliance pathway, many of these comments ignore the timing flexibilities of the trading program, which (particularly with the changes to the backstop daily emissions rate in this final rule) allow sources to temporarily comply through means other than SCR retrofit if they experience any site-specific retrofit limitations that increase their time frame. Also, historical examples of SCR retrofit projects that exceeded 48 months in duration do not necessarily demonstrate that such projects are impossible in less than 48 months, but rather that they can extend beyond the timeframe if no requirements or incentives are in place for a faster installation. Some also cite site-specific conditions that resulted an outlier cases of project timing that would not be representative of the conditions expected at future retrofit projects.[216]

Comment: Some stakeholders suggested that EPA's cost estimates of $11,000 per ton are premised on a 15-year book life of the equipment and are therefore too optimistic for units that plan to retire in well under 15 years.

Response: EPA analysis of SCR retrofit cost reflects a representative value for the technology based on a weighted average cost. The underlying data and the discussion in the EGU NO_X Mitigation Strategies Final TSD illustrates that these costs can vary significantly at the unit level based on factors such as the length of time a pollution control technology would be in operation, the capacity factor of the unit (*i.e.,* how much does it operate), its size or potential to emit, and its baseline emissions rate. The EPA has not in prior transport rulemakings used such factors as justification to excuse any source that is significantly contributing to nonattainment or interfering with maintenance in another state from eliminating that significant contribution as expeditiously as practicable. Unlike under other statutory provisions that may require retrofit of emissions controls on existing sources, such as under CAA section 111(d) or CAA section 169A, there is no remaining useful life factor expressly identified as a justification to relax the requirements of CAA section 110(a)(2)(D)(i)(I). EPA continues to believe that where an emissions control strategy has been identified at Step 3 that is cost-effective on a regional scale and provides meaningful downwind air quality improvement, and is thus appropriately identified as necessary to eliminate significant contribution under the good neighbor provision, it would not be appropriate to allow emissions to continue in excess of those achievable emissions reductions beyond the timeframe for expeditious implementation of reductions as provided under the larger title I structure of the Act for attaining and maintaining the NAAQS. The court in *Wisconsin* recognized that where such emissions have been identified, they should be eliminated as expeditiously as practicable, and in line with the

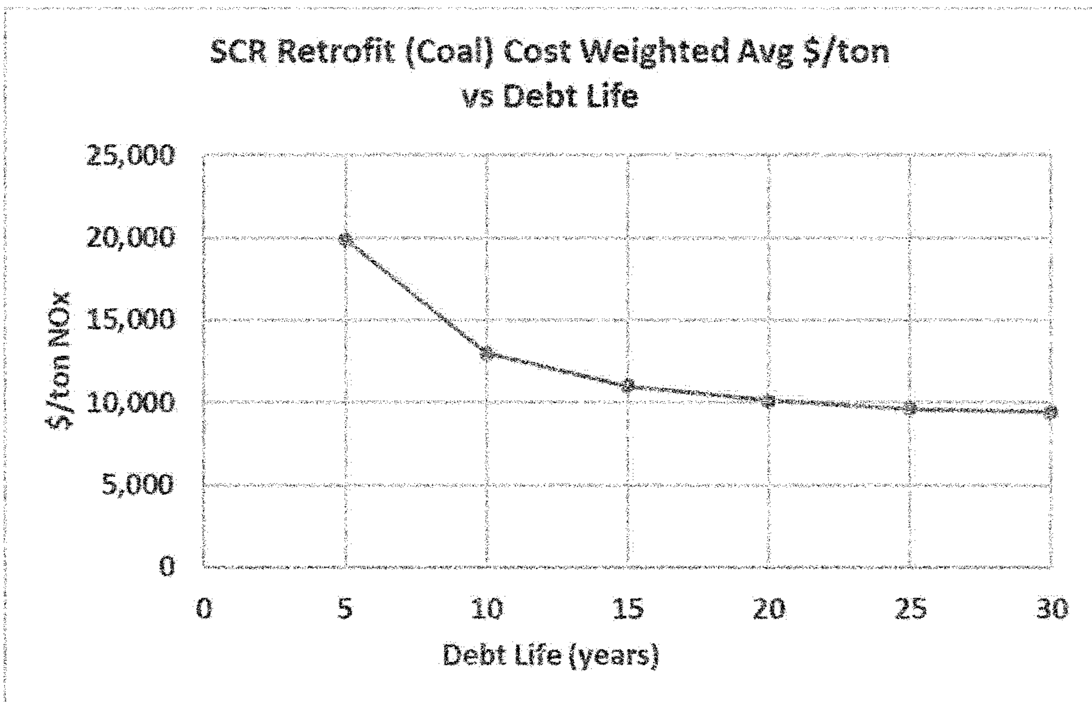
[215] *See* ''Regulatory Impact Analysis for 2015 Good Neighbor Plan, Appendix 4A: Inflation Reduction Act EGU Sensitivity Run Results.'' EPA estimated the compliance costs and emissions changes of the final rule in the presence of the IRA, but given time and resource constraints, did not quantify benefits for this sensitivity.

[216] Commenters, for example, cited the timing of SCR installation at Sammis 6 and 7. Here, the SCR design and material delivery schedule were tailored to meet unique site conditions that were unlike many other SCR systems where large modules can be used to maximize shop and ground assembly techniques. Additional information is available at *https://www.babcock.com/home/about/resources/success-stories/sammis-plant.*

attainment schedule for downwind areas, which, for the 2015 ozone NAAQS, is provided in CAA section 181. 938 F.3d at 313–20.

Further, EPA observes that more than one-third of the identified SCR retrofit potential (in terms of generating capacity) has no planned retirement date within 15 years, and therefore the cost of pollution control technology on such units would likely be lower, holding all other parameters equal, on a dollar per ton basis by virtue of the length of time the pollution control equipment may be in operation. Nor does EPA agree that units that would retire in less than 15 years should automatically be considered to face an unreasonably higher cost burden. Based on data analyzed in the EGU NO_X Mitigation Strategies Final Rule TSD, we find that the cost per ton associated with SCR retrofit technology does not begin to increase significantly above the $11,000/ton benchmark unless units have dramatically lower operating capacity or retire in less than 5 years' time—as illustrated in Figure 1 to section V.B.1.e of this document.

Figure 1 to section V.B.1.e: SCR Retrofit Cost Weighted Average $/ton vs Debt Life[217]



Finally, EPA's identification of this mitigation strategy is not meant to be limited only to units that experience a retrofit cost that is less than the representative cost threshold. First, that threshold represents an average, meaning that EPA's analysis already recognizes that some units on a facility-specific basis may face costs higher than that threshold. Further, EPA identifies this technology as widely available, implemented in practice already at many existing EGUs, and now standard for any coal-fired unit coming online in the past 25 years. More than 66 percent of the current large coal fleet already has such controls in place. Even if the cost were higher for some units for the reasons provided by commenters—and there were no less costly means provided to them to achieve the same level of emissions reduction (which the trading program allows for)—that would not necessarily obviate EPA's basis for finding that an emissions-reduction requirement commensurate with this standard pollution control practice for this unit type is warranted. The implementation of emissions reductions through a trading program, and its corresponding compliance flexibilities, make the use of a single representative cost all the more appropriate in this assessment. Therefore, upon reviewing all of the data including the information supplied by commenters, and even accounting for certain units' announced plans to retire earlier than an assumed 15-year book life for SCR retrofit technology, EPA finds its representative cost for this technology to be appropriate and reasonable for purposes of analysis under CAA section 110(a)(2)(D)(i)(I) and maintains this cost estimate in the final rule.

However, in recognition of the unique circumstances related to the transition of the power sector away from coal-fired and other high-NO_X emitting fuels and generating technologies, which is anticipated to accelerate in the late 2020s and into the 2030s, EPA has adjusted the final rule to avoid imposing a capital-intensive control technology retrofit obligation which could have overall net-negative environmental consequences (*e.g.,* by extending the life of a higher-emitting EGU or necessitating the allocation of material and personnel that could be used for more advanced clean-technology

[217] "Debt Life" refers to the term length, or duration, for a loan used to finance the retrofit.

innovations). For units that plan to retire by 2030, the final rule—by extending the daily backstop rate to 2030—allows these units to continue to operate, so long as they comply with the mass-based emissions trading program requirements.[218] Therefore, a unit experiencing a higher dollar per ton retrofit cost due to retirement plans has the flexibility to install less capital intensive controls such as SNCR, procure less costly allowances through either banking or purchase, or they may also reduce their allowance holding requirement through reduced utilization consistent with their phasing out towards a planned retirement date. This flexibility that EPA has included in the final rule is discussed in further detail in section VI.B of this document.

Comment: Some commenters suggested that the 0.05 lb/mmBtu emissions rate assumed for new SCRs at large coal units is not achievable at all coal units with retrofit potential and that EPA should raise this performance assumption to a value of 0.08 lb/mmBtu consistent with that assumption for existing SCRs.

Response: First, EPA believes the commenter misunderstands its intention with the 0.05 lb/mmBtu SCR rate assumption. This is meant to reflect a representative assumption for emissions rate performance for new SCR installed on the currently unretrofitted coal fleet—in this respect, it represents an average, not a maximum. EPA recognizes that some units will likely perform better (*i.e.,* lower) than this rate and some will potentially perform worse (*i.e.,* higher) than this rate—but that 0.05 lb/mmBtu is a reasonable representation of new SCR retrofit potential on a fleet-wide basis and for identifying expected state and regional emissions reduction potential from this technology. It would be inappropriate for EPA to use the worst performing tier of new SCR retrofit for this representative value. Moreover, EPA's review of historical environmental performance for recently installed SCRs does not support any indication that 0.05 is not representative of the retrofit potential for the fleet. EPA found that three quarters of the SCR retrofit projects completed in the last 15 years have achieved a rate of 0.05 lb/mmBtu or better on a monthly or seasonal basis. Moreover, its review of the engineering literature and consultation with third party pollution control engineering consultancies suggests that vendors are often willing to guarantee 0.05 lb/mmBtu seasonal performance for new SCR retrofit projects. Current SCR catalyst suppliers provide NO_X emissions warranties based at the catalyst's end-of-life period, often after 16,000 to 24,000 hours of operations, with newer catalyst achieving similar or better NO_X removal rates. Standard commercial terms, made by the purchaser to the SCR Retrofit supplier, can specify a system capable of meeting the proposed NO_X emissions rate and define the catalyst operational life before replacement. Thus, achieving the proposed reduction rates is accomplished through the buyer specifying the SCR retrofit requirements and the supplier providing an optimized system design and installing sufficient catalyst for the targeted end-of-life NO_X emissions rate. The agency is confident that SCR retrofit suppliers will be able to warrant their offerings for the emissions rates proposed in the regulation and to provide sufficient operating life for the affected sector.

Comment: Some commenters suggest that the evaluation of pollution control installation cost at Step 3 should be segmented depending on unit characteristics, and by failing to do so understate the cost of retrofitting SCR controls. In particular, these commenters note that units with lower capacity factors, different coal ranks, with pre-existing controls—such as SNCR—face substantially higher dollar per ton reduced costs than those that do not have such controls in place and should not be identified as a cost-effective mitigation strategy.

Response: Consistent with prior CSAPR rulemakings, at Step 3 EPA evaluates a mitigation technology and its representative cost and performance for the fleet on average. This representative cost is inclusive and robust to the portion of the fleet that may face higher dollar per ton cost. Both the ''Technical Support Document (TSD) for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, Docket ID No. EPA–HQ–OAR–2021–0668, EGU NO_X Mitigation Strategies Proposed Rule TSD'' (Feb. 2022), hereinafter referred to as the EGU NO_X Mitigation Strategies Proposed Rule TSD, and the EGU NO_X Mitigation Strategies Final TSD discuss the SCR retrofit cost specific to the segment of the fleet that has a SNCR in place and notes that those unit-level higher retrofit cost estimates are factored into its determination of the fleet-wide representative number. Although EPA believes its representative cost are appropriate and underpinned by operating assumptions reflective of the fleet averages, it nevertheless examined how cost would vary based on some of the variables highlighted by commenter. The EPA derived its capacity factor assumption based on expected future operations of this fleet segment that are inclusive of units operating at a range of capacity factors. It also examined how cost would change assuming different coal rank, assuming different book life, and different reagent cost. These analyses are discussed and shown in Appendix B of the EGU NO_X Mitigations Strategies Final Rule TSD and demonstrate that even under different operating assumptions, the variation in cost does not reach a point that would reverse EPA's finding regarding the appropriateness of this technology as part of this final rule's control stringency. Moreover, as discussed in section V.D of this document, EPA identifies appropriate mitigation strategies based on multiple factors—not solely on cost, and there is no indication that an individual unit's higher retrofit cost would obviate the appropriateness of retrofitting this standard and best practice technology at the unit. Finally, in prior rules and in the proposal, EPA recognized that some units will have higher cost and some will have lower cost relative the fleetwide representative value provided. Implementing the region and state reduction requirements through a mass-based trading program provides a means of alternative lower cost compliance for those sources particularly concerned about the higher retrofit cost at their unit.

Comment: Some commenters suggested that EPA's proposed representative cost for SCR pollution control is likely too high and overstates the true cost of such control. They also noted it aligns with agency precedent. These commenters claim that EPA's cost recovery factor is higher than necessary (thus inflating the cost) as it reflects a weighting of utility-owned to merchant-owned plants that is representative of the fleet, but not the unretrofitted fleet with this retrofit potential identified in this rule. They also noted that EPA's assumed interest rate informing the cost estimate was higher than the prime rate in June of 2022.

Response: EPA agrees that its approach for identifying representative cost thresholds is aligned with prior rules and agrees that its approach is reasonable. As the commenter points out, prime rates and cost recovery factors may indeed be lower in recent data than those assumed by EPA for future years. However, given the

[218] In the RIA, EPA has modeled the mass-based budgets that are premised on retrofit of SCR technology with the option of complying through other strategies, and finds that they are readily achievable through those other strategies.

volatility among these metrics, EPA believes its choices are appropriate to build cost estimates that are robust to future uncertainty, and if these cost input factors do materialize to be the lower values highlighted by commenter, then it will result in a lower cost assumed in this final rule, but would not otherwise alter any of the stringency identification or regulatory findings put forward in this final rule. EPA performed a cost sensitivity analysis in Appendix B of the EGU NO_X Mitigation Strategies Final Rule TSD which shows how cost for this technology would vary based on different assumed levels for this variable. This analysis shows that under lower interest rates such as those put forward by commenter, that technology cost would drop by approximately 15 percent relative to the representative values put forward in this rule.

f. Generation Shifting

At proposal, EPA considered intrastate emissions reduction potential from generation shifting across the representative dollar per ton levels estimated for the emissions controls considered in previous sections. As the cost of emitting NO_X increases, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. Consequently, there is more generation shifting at higher cost NO_X-control levels.

The EPA recognizes that imposing a NO_X-control requirement on affected EGUs, like any environmental regulation, internalizes the cost of their pollution, which could result in generation shifting away from those sources toward other generators offering electricity at a lower pollution cost. If, in the context of a market-based allowance trading program form of implementation, the EPA imposes a preset emissions budget that is premised only on assumed installation, optimization, and continued operation of unit-specific pollution control technologies, with no accounting for the likely generation shift in the marketplace away from these higher-polluting sources, that preset emissions budget will contain more tons than would be emitted if the affected EGUs achieved the emissions performance level (on a rate basis) selected at step 3. Hence, EPA has previously quantified and required expected emissions reductions from generation shifting in prior transport rules to avoid undermining the program's incentive to install, optimize, and operate controls identified in the Agency's determinations regarding the requisite level of emissions control at Step 3. *See, e.g.,* 81 FR 74544–45; 76 FR 48280.

As in these prior rules, at proposal, the EPA did not identify generation shifting as a primary mitigation strategy and stringency measure on its own, but included emissions reductions from this strategy as it would be projected to occur in response to the selected emissions control stringency levels (and corresponding allowance price signals in step 4 implementation). For this rule's proposal, the EPA only specified emissions reductions from generation shifting in its preset budget calculations for 2023 and 2024. Because this rule's dynamic budget methodology applies the selected control stringency's emissions rates to the most recently reported heat input at each affected EGU, dynamic budgeting effectively serves a similar purpose to our ex ante quantification of emissions reduction potential from generation shifting for preset budgets in prior transport rules, *i.e.,* to adequately and continuously incentivize the implementation of the emissions control strategies selected at Step 3. Therefore, dynamic budgets under this rule's program moot the need to specify discrete emissions reduction potential from generation shifting for those control periods, as they automatically reflect whatever generation balance affected EGUs would determine in the marketplace inclusive of their response to the emissions performance levels imposed by this rule.

Comment: Commenters offered both support for and opposition against the inclusion of generation shifting at Step 3 analysis for EGUs. Those in support noted that inclusion of emissions reductions from generation-shifting is integral to the successful implementation of the pollution control measures identified in the selected control stringency at Step 3. Those opposed generally argued the EPA was overestimating reduction potential from generation shifting in light of recent volatility and high prices in the markets for lower emitting fuels such as natural gas. Commenters also noted the electrical grid in certain regions has constraints that would make generation shifting more difficult than the EPA assumed. Commenters also asserted that the EPA did not have the legal authority to require generation shifting.

Response: The EPA disagrees with these comments regarding our legal authority but notes this issue is not relevant for purposes of this final action. The EPA continues to believe it has authority under CAA section 110(a)(2)(D)(i)(I) to consider and require emissions reductions from generation shifting if the EPA were to find that strategy was necessary to eliminate significant contribution. However, based on circumstances currently facing affected EGUs, as well as the inherent strength of the dynamic budget methodology to automatically reflect the market-determined balance of generation across sources responding to this rule, the EPA is not specifying emissions reduction potential from generation shifting as a part of the Step 3 analysis, nor to require any emissions reductions from generation shifting in preset budgets formulated under Step 4 for any control period, for this final rule.

Currently observable market conditions (*e.g.,* fuel prices) present unusual uncertainty with respect to key economic drivers of generation shifting. The availability of emissions reductions through generation shifting, and the magnitude of those emissions, is dependent on the availability and cost of substitute generation. The primary driver of near-term generation shifting-based emissions reductions has been shifting to lower-emitting natural gas generation. Recent volatility and high prices in the natural gas market have increased the uncertainty and reduced the potential of this emissions control strategy at any given cost threshold in the near term. For example, Henry Hub natural gas prices went from under $3.00/mmBtu during most of the last decade to an average of nearly $8.00/mmBtu for the most recent (2022) ozone season before declining sharply at the start of 2023. The current volatility in natural gas prices reduces the availability of emissions reductions from generation shifting and make its identification and quantification too uncertain for incorporation into Step 3 emissions reduction estimates for this rulemaking.

The Step 4 dynamic budget-setting process of this rule obviates the need to specify and require discrete emissions reductions from generation shifting under Step 3. As discussed in section VI of this document, the EPA in this final rule will implement a budget-setting approach that relies on two components: first, we have calculated "preset" budgets that reflect the best information currently available about fleet change over the period 2023 through 2029. Second, beginning in 2026, dynamic state emissions budgets will be calculated that will reflect the balance of generation across sources reported to EPA by EGU operators. Between 2026 and 2029, the actual budget that will be implemented will reflect the greater of either the preset budget or the dynamic budget calculation; from 2030 onwards, the budgets will be set only through the dynamic budget calculation. This overall approach is well suited for a period of significant power sector transition driven by a variety of economic, policy, and regulatory forces and allows for the balance of generation in this period to adjust in response to these forces while nonetheless ensuring that the budgets will continuously incentivize the emissions control stringency identified at Step 3. See section VI.B.4 of this document for further discussion on the interaction of preset and dynamic budgets during the 2026–2029 time period. With these approaches, and on the present record before the Agency, we conclude that the estimation and incorporation of specified emissions reductions from generation shifting at Step 3 is not necessary to eliminate significant contribution from EGUs for the 2015 ozone NAAQS through this rule's program implementation.

In previous CSAPR rulemakings, the EPA included generation shifting in the budget setting process to capture those reductions that would occur through shifting generation as an economic response to the control stringency determined based on the selected NO_X control strategies. *See, e.g.,* 81 FR 74544–45. ''Because we have identified discrete cost thresholds resulting from the full implementation of particular types of emissions controls, it is reasonable to simultaneously quantify the reduction potential from generation shifting strategy at each cost level. Including these reductions is important, ensuring that other cost-effective reductions (*e.g.,* fully operating controls) can be expected to occur.'' EGU NO_X Mitigation Strategies Final Rule TSD (EPA–HQ–OAR–2015–0500–0554), at 11–12.

Commenters on this rule and prior transport rules have observed that using preset budgets to factor in generation shifting is flawed in that it results in EPA incorporating specific quantities of emissions reductions from discrete levels of generation shifting that are projected to occur but may in fact ultimately transpire differently in the marketplace. Commenters on this rule claim that other variables, such as constraints in transmission capacity or changes in fuel prices, can drive such differences in projected versus realized generation shifting, and these concerns are particularly exacerbated in a time of significant uncertainty around energy supplies and markets together with new laws passed by Congress (*e.g.,* the Infrastructure Investment and Jobs Act and the Inflation Reduction Act) driving the current transformation of the power sector. By refraining in this rule from specifying discrete emissions reductions from generation shifting in preset budgets and instead relying on a dynamic budgeting approach to reflect market-driven generation patterns, EPA ensures that its budgets remain sufficiently stringent over the long term to continually incentivize the emissions control stringency it determined to be cost-effective and therefore appropriate to eliminate significant contribution at Step 3. Thus, dynamic budgeting addresses the same concern that animated our use of generation shifting in the CSAPR rulemakings, but in doing so uses a market-following approach that will accommodate, over the long term, unforeseen drops or increases in heat input levels.

g. Other EGU Mitigation Measures

The EPA requested comment on whether other EGU ozone-season NO_X Mitigation technologies should be required to eliminate significant contribution. For instance, the EGU NO_X Mitigation Strategies Proposed and Final Rule TSDs discussed certain mitigation technologies that have been applied to ''peaking'' units (small, low-capacity factor gas combustion turbines often only operating during periods of peak demand).

Comment: Some commenters emphasized that simple cycle combustion turbines play a significant role in downwind contribution, and they highlight that states such as New York have imposed emissions limits on these sources acknowledging their impact on downwind nonattainment. These commenters suggest that EPA pursue and expedite the implementation of these or similar mitigation measures.

Response: As explained in greater detail in the EGU NO_X Mitigation Strategies Final TSD, both the configuration and operation of this segment of the EGU fleet reflects significant variability among units and across time. In other words, one unit may have a capacity factor in a given year that is one hundred times greater than a similar unit in that same year, or even than its own capacity factor from a preceding year. This type of variability and heterogeneity make it unlikely that there is a single cost-effective control strategy across this fleet segment, and commenters did not provide evidence to the contrary. EPA's analysis discussed in the EGU NO_X Mitigation Strategies Final Rule TSD highlights that there are 32 units emitting more than 10 tons per year on average for the 2019–2021 ozone seasons and lacking combustion controls or more advanced controls (totaling approximately 1,000 tons of ozone season NO_X emissions in 2021). EPA analysis estimates a representative cost of $22,000 per ton for dry low NO_X burners or ultra-low NO_X burners at these simple cycle combustion turbines, and over $100,000 per ton for SCR retrofit at some combustion turbines. Therefore, EPA does not identify any such uniform mitigation measure at Step 3 when estimating reduction potential.

Nonetheless, the EPA recognizes that these simple cycle combustion turbines may have cost-effective emissions-reduction opportunities. These units are included in the emissions trading program and therefore, as in prior transport rules, the program continues to subject them to an allowance holding requirement under this rule which will likely incentivize any available cost-effective NO_X reductions from these EGUs. For instance, emissions rates from these units in New York were considerably lower in 2022, when they faced a high allowance price, versus 2021, when the allowance price was much lower. Therefore, we find that the appropriate treatment of these units in this final rule is to continue to include them in the emissions trading program to incentivize cost-effective emissions reductions, but EPA does not find the magnitude or consistency of cost-effective mitigation potential to establish a specific increment of emissions reduction through a specific Step 3 emissions control determination. Moreover, while EPA's program will incentivize any available cost-effective reductions within this cadre of units (and such behavior is captured in its final program evaluation and modeling the *RIA*), it does not obviate the need for the other EGU cost-effective reductions elsewhere as suggested by some commenters.

2. Non-EGU or Stationary Industrial Source NO_X Mitigation Strategies

In the early stages of preparing the proposed FIP, the EPA evaluated air quality modeling information, annual emissions, and information about potential controls to determine which industries, beyond the power sector, could have the greatest impact on downwind receptors' air quality and therefore the greatest impact in providing ozone air quality improvements in affected downwind states through reducing those emissions. Specifically, the EPA conducted a screening assessment focused on individual emissions units with >100 tpy of actual NO_X emissions in 23 upwind states. Once the industries were identified, the EPA used its Control Strategy Tool to identify potential emissions units and control measures and to estimate emissions reductions and compliance costs associated with application of non-EGU emissions control measures. The technical memorandum ''Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026'' (''Non-EGU Screening Assessment'' or ''screening assessment'') lays out the analytical framework and data used to prepare proxy estimates for 2026 of potentially affected non-EGU facilities and emissions units, emissions reductions, and costs.[219]

This screening assessment was not intended to identify the specific emissions units subject to the proposed emissions limits for non-EGU sources but was intended to inform the development of the proposed rule by identifying proxies for (1) non-EGU emissions units that potentially had the most impact in terms of the magnitude of emissions and potential for emissions reductions, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. This information helped shape the proposed rule.

To further evaluate the industries and emissions unit types identified by the screening assessment and to establish the applicability criteria and proposed emissions limits, the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies, rules in approved SIP submittals, consent decrees, and permit limits. That evaluation is detailed in the Proposed Non-EGU Sectors TSD prepared for the proposed FIP.[220]

In this final rule, for purposes of this part of the Step 3 analysis, the EPA is retaining emissions control requirements for these industries and many of the emissions unit types included in the proposal. However, based on comments that credibly indicated in certain cases that emissions reduction opportunities are either not available for certain unit types or are at costs that are far greater than the EPA estimated at proposal, the EPA has changed the final rule to either remove or adjust the applicability criteria for such units. For a detailed discussion of the changes between the proposed FIP and this final rule, in emissions unit types included and in emissions limits, see section VI.C of this document. Tables I.B–2 through I.B–7 in section I.B of this document identify the emissions units and applicable emissions limitations, and Table II.A–1 in section II.A of this document identifies the industries included in the final rule.

For the final rule, to determine NO_X emissions reduction potential for the non-EGU industries and emissions unit types, with the exception of Solid Waste Combustors and Incinerators, we used a 2019 inventory prepared from the emissions inventory system (EIS) to estimate a list of emissions units captured by the applicability criteria for the final rule. For Solid Waste Combustors and Incinerators, the EPA estimated the list of covered units using the 2019 inventory, as well as the NEEDS-v6-summer-2021-reference-case workbook.[221] Based on the review of RACT, NSPS, NESHAP rules, as well as SIPs, consent decrees, and permits, we also assumed certain control technologies could meet the final emissions limits.[222] We did not run the Control Strategy Tool to estimate emissions reductions and costs and instead programmed the assessment using R.[223] Using the list of emissions units estimated to be captured by the final rule applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database (CMDB),[224] the EPA estimated NO_X emissions reductions and costs for the year 2026. We estimated emissions reductions using the actual emissions from the 2019 emissions inventory. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records.

The EPA recognized both at proposal and in the final rule that the cost per ton of emissions controls could vary by industry and by facility. The $7,500 marginal cost/ton threshold reflected in the Non-EGU Screening Assessment functioned as a relative, representative cost/ton level. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. The value was used to identify potentially cost-effective controls for further evaluation.

In the final rule, partly in recognition of the many comments indicating widely varying cost-per-ton values across industries and facilities, the EPA has updated its analysis of costs for the covered non-EGU industries. This data is summarized in the Technical Memorandum ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' available in the docket. We further respond to comments on the screening assessment in section 2.2 of the response to comments document.

3. Other Stationary Sources NO_X Mitigation Strategies

As part of its analysis for this final rule, the EPA also reviewed whether NO_X mitigation strategies for any other stationary sources may be appropriate. In this section, the EPA discusses three classes of units that have historically been excluded from our interstate air transport programs: (1) solid waste incineration units, (2) electric generating units less than or equal to 25 MW, and (3) cogeneration units. EPA's initial assessment did not lead it to propose inclusion of the units in these categories. However, EPA requested comment on whether any particular units within this category may offer cost-effective reduction potential.

Based on our request for comment, comments received, and our further evaluation, the EPA is including emissions limits and associated control requirements for the ozone season for solid waste incinerator units in this final rule, in line with the requirements we laid out for comment at proposal. Our analysis in this final rule confirms that these units have emissions reductions of a magnitude, degree of beneficial impact, and cost-effectiveness that is on par with the units in other industrial sectors included in this final rule.

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[219] The memorandum is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.*

[220] The TSD for the proposed FIP is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.*

[221] The workbook is available here: *https://www.epa.gov/power-sector-modeling/national-electric-energy-data-system-needs-v6.*

[222] The Final Non-EGU Sectors TSD is available in the docket.

[223] R is a free software environment for statistical computing and graphics. Additional information is available here: *https://www.r-project.org/.*

[224] More information about the Control Strategy Tool (CoST) and the control measures database (CMDB) can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

For electric generating units less than 25 MW and cogeneration units previously exempted from EGU emissions budgets established through ozone interstate transport rules, the EPA has determined that these units should not be treated as EGUs in this final rule.

The EPA provides a summary of these three segments, their emissions control opportunities, and potential air quality benefits in the following sections. Additional considerations are further discussed in the EGU NO_X Mitigation Strategies Final TSD and in the *RTC* Document.

a. Municipal Solid Waste Units

At proposal, the EPA solicited comments on whether NO_X emissions reductions should be sought from municipal waste combustors (MWCs) to address interstate ozone transport, specifically on potential emissions limits, control technologies, and control costs. The EPA requested comment on emissions limits of 105 ppmvd on a 30-day rolling average and a 110 ppmvd on a 24-hour block average based on determinations made in the June 2021 Ozone Transport Commission (OTC) *Municipal Waste Combustor Workgroup Report* (OTC MWC Report). *See* 87 FR 20085–20086. The OTC MWC Report found that MWCs in the Ozone Transport Region (OTR) are a significant source of NO_X emissions and that significant annual NO_X reductions could be achieved from MWCs in the OTR using several different technologies, or combination of technologies at a reasonable cost. The OTC MWC report is included in the docket for this action.

Comment: The EPA received multiple comments supporting the inclusion of emissions limits for MWCs in the final rule. Commenters noted that MWCs are significant sources of NO_X that contribute to ozone problems in the states covered by the proposal. Multiple commenters referenced the OTC MWC report to contend that NO_X emissions from MWCs could be significantly reduced at a reasonable cost. Some commenters reasoned that sources closer to downwind monitors, including MWCs, should be regulated as a more targeted approach and a means to prevent overcontrol of upwind sources. Commenters also noted that the OTC recently signed a memorandum of understanding (MOU) requesting that OTC member states develop cost effective solutions and select the strategy or combination of strategies, as necessary and appropriate, that provides both the maximum certainty and flexibility for that state and its MWCs. Additionally, multiple commenters noted that MWCs are often located in economically marginalized communities or communities of color. Lastly, one commenter stated that MWCs were arbitrarily excluded from the non-EGU screening assessment prepared for the proposal.

Response: As described in section VI.B.2 of the notice of proposed rulemaking, the EPA assessed emissions reduction potential from non-EGUs by preparing a screening assessment to identify those industries that could have the greatest air quality impact at downwind receptors. While the EPA did not prepare an updated non-EGU screening assessment in preparation for this final rule, the Agency did evaluate MWCs using the criteria developed in the screening assessment for proposal and determined that MWCs should be included in this rulemaking. A discussion of this analysis for MWCs is available in the *Municipal Waste Combustor Supplement to February 28, 2022 Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* which is available in the docket for this rule.

Considering EPA's conclusion that MWCs should be included in this final rule if EPA applied the same criteria developed in the screening assessment for proposal, the findings from the OTC MWC report and recent MOU, the fact that many state RACT NO_X rules apply to MWCs, and information received during public comment, the EPA finds that MWCs should be included in this final rule. Thus, the EPA is finalizing NO_X emissions limits and compliance assurance requirements for large MWCs as defined in the regulatory text at § 52.46 and as described in this section.

Comment: Some commenters did not support the inclusion of emissions limits for MWCs in the final rule. Some commenters suggested that the inclusion of NO_X limits in a FIP is not necessary to continue to reduce NO_X emissions from MWCs or to address interstate transport problems. Some commenters noted that many of the MWCs in the states covered by the proposal are already subject to RACT-based NO_X emissions limits that are below the current Federal NSPS NO_X emissions limits for MWCs under 40 CFR part 60, subparts Cb and Eb. One commenter noted that MWCs do not always account for a large percentage of statewide NO_X emissions. Others suggested that voluntary industry actions are also driving downward trends of NO_X emissions for some MWCs. Some commenters also asserted that regulation could interfere with state waste reduction policies and associated environmental considerations.

Response: Regarding the comments that some MWCs are already subject to RACT NO_X emissions limits, the EPA acknowledges that some states included in this rulemaking have promulgated RACT NO_X emissions limits that apply to certain MWCs, including some that are lower than current MWC NSPS NO_X emissions limits. The EPA does not consider a source to be exempt from this rulemaking just because the source may be subject to other regulatory requirements. As noted, the Agency did evaluate MWCs using the criteria developed in the screening assessment for proposal and has concluded that MWCs should be included in this rulemaking. In considering the emissions limits that are being finalized in this rulemaking, the EPA reviewed existing state RACT rules as described in section VI.C.6 of this document and the ''Technical Support Document (TSD) for the Final Rule, Docket ID No. EPA–HQ–OAR–2021–0668, Non-EGU Sectors TSD'' (Mar. 2023), hereinafter referred to as Final Non-EGU Sectors TSD. We note that sources already subject to RACT NO_X emissions limits that are equal to or more stringent than the limits finalized in this rulemaking will have the option to streamline regulatory requirements through the Title V permitting process.

Regarding the statement that regulation could interfere with state waste reduction policies and associated environmental considerations, the EPA acknowledges that MWCs serve an important role in municipal solid waste management programs, and that many function as cogeneration facilities that produce electrical power for the power grid. The EPA also analyzed control costs and determined that the required NO_X emissions limits for MWCs can be achieved at a reasonable cost, as described in section VI.C.6 of this document, the Final Non-EGU Sectors TSD, and the OTC MWC Report. Although the EPA does not expect these regulations to disrupt the ability of the industry to provide municipal solid waste and electric services, to the extent a facility is unable to comply with the standards due to technical impossibility or extreme economic hardship, the final rule includes provisions for facility operators to apply for a case-by-case alternative emissions limit. *See* section VI.C of this document and 40 CFR 52.40(d). In addition, for MWC facilities that are unable to comply with the standard by the 2026 ozone season, the final rule includes provisions for requesting limited extensions of time to comply. *See* section VI.C and 40 CFR 52.40(c).

b. Electric Generating Units Less Than or Equal to 25 MW

The EPA has historically not included control requirements for emissions for electric generating units less than or equal to 25 MW of generation for three primary reasons: low potential reductions, relatively high cost per ton of reduction, and high monitoring and other compliance burdens. In the January 11, 1993, Acid Rain permitting rule, the EPA provided for a conditional exemption from the emissions reduction, emitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions. *See* 63 FR 57484. The NO_X SIP Call identified these as *Small Point Sources.* For the purposes of that rulemaking, the EPA considered electricity generating boilers and turbines serving a generator 25 MWe or less, to be small point sources. The EPA noted that the collective emissions from small sources were relatively small and the administrative burden to the states and regulated entities of controlling such sources was likely to be considerable. As a result, the rule did not assume reductions from those sources in state emissions budgets requirements (63 FR 57402). Similar size thresholds have been incorporated in subsequent transport programs such as CAIR and CSAPR. As these sources were not identified as having cost-effective reductions and so were not included in those programs, they were also exempted from certain reporting requirements and the data for these sources is, therefore, not of the same caliber as that of covered larger sources.

EPA's preliminary survey of current data, compared to this initial justification, does not appear to offer a compelling reason to depart from this past practice by requiring emissions reductions from these small EGU sources as part of this rule. For instance, as explained in the EGU NO_X Mitigation Strategies Final Rule TSD, EPA has evaluated the costs of SCR retrofits at small EGUs using its Retrofit Cost Analyzer and found that such controls become markedly less cost-effective at lower levels of generating capacity. This analysis concluded that, after controlling for all other unit characteristics, the dollar per ton cost for a SCR retrofit increases by about a factor of 2.5 when moving from a 500 MW to a 10 MW unit, and a factor of 8 when moving to a 1 MW unit.[225] Moreover, the EPA estimates that under 6 percent of nationwide EGU emissions come from units that are less than 25 MW and not covered by current applicability criteria due to this size exemption threshold. Therefore, the EPA is not finalizing any emissions reductions for these units.

Comment: EPA received comment supporting the continued application of the 25 MW threshold.

Response: Consistent with prior rules, the proposal, and stakeholder comment, EPA is continuing to apply its 25 MW applicability threshold for EGUs in this rulemaking. EPA did not find compelling comment to reverse its determination that (1) these sources offer low potential reductions, (2) have relatively high cost per ton, and (3) have high monitoring and other compliance burdens.

c. Cogeneration Units

Consistent with prior transport rules, fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy (generally referred to as ''cogeneration units'') and that meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program would be subject to the emissions reduction requirements established in this rulemaking for EGUs. However, those applicability criteria—which the EPA is not altering in this rulemaking (*see* section VI.B.3 of this document)—exempt some cogeneration units from coverage as EGUs under the trading program. The EPA is finalizing that fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy and that do not meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs would not be subject to the Group 3 emissions trading program. However, to the extent a cogeneration unit meets the applicability criteria for industrial non-EGU boilers covered by this rule, that unit will be subject to the relevant requirements and is not exempted by virtue of being a cogeneration unit.

According to information contained in the EPA's Combined Heat and Power Partnership's document ''Catalog of CHP Technologies'',[226] there are 4,226 CHP installations in the U.S. providing 83,317 MWe of electrical capacity. Over 99 percent of the installations are powered by 5 equipment types, those being reciprocating engines (52 percent), boilers/steam turbines (17 percent), gas turbines (16 percent), microturbines (8 percent), and fuel cells (4 percent). The majority of the electrical capacity is provided by gas turbine CHP systems (64 percent) and boiler/steam turbine CHP systems (32 percent). The various CHP technologies described herewith are available in a large range of sizes, from as small as 1 kilowatt reciprocating engine systems to as large as 300 megawatt gas turbine powered systems.

NO_X emissions from rich burn reciprocating engine, gas turbine, and microturbine systems are low, ranging from 0.013 to 0.05 lb/mmBtu. NO_X emissions from lean burn reciprocating engine systems and gas-powered steam turbines systems range from 0.1 to 0.2 lb/mmBtu. The highest NO_X emitting CHP units are solid fuel-fired boiler/steam turbine systems which emit NO_X at rates ranging from 0.2 to 1.2 lb/mmBtu.

Under the final rule (consistent with prior CSAPR rulemakings), certain cogeneration units would be exempt from coverage under the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs. Specifically, the trading program regulations include an exemption for a unit that qualifies as a cogeneration unit throughout the later of 2005 or the first 12 months during which the unit first produces electricity and continues to qualify through each calendar year ending after the later of 2005 or that 12-month period and that meets the limitation on electricity sales to the grid. To meet the trading program's definition of ''cogeneration unit'' under the regulations, a unit (*i.e.,* a fossil-fuel-fired boiler or combustion turbine) must be a topping-cycle or bottoming-cycle type that operates as part of a ''cogeneration system.'' A cogeneration system is defined as an integrated group of equipment at a source (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. A topping-cycle unit is a unit where the sequential use of energy results in production of useful power first and then, through use of reject heat from such production, in production of useful thermal energy. A bottoming-cycle unit is a unit where the sequential use of energy results in production of useful thermal energy first, and then, through use of reject heat from such production, in production of useful

[225] Preliminary estimate based on representative coal units with starting NO_X rate of 0.2 lb/mmBtu, 10,000 BTU/kwh, and assuming 80 percent reduction.

[226] This document is available at: *https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf.*

power. To qualify as a cogeneration unit, a unit also must meet certain efficiency and operating standards in 2005 and each year thereafter. The electricity sales limitation under the exemption is applied in the same way whether a unit serves only one generator or serves more than one generator. In both cases, the total amount of electricity produced annually by a unit and sold to the grid cannot exceed the greater of one-third of the unit's potential electric output capacity or 219,000 MWh. This is consistent with the approach taken in the Acid Rain Program (40 CFR 72.7(b)(4)), where the cogeneration-unit exemption originated.

The EPA requested comment on requiring fossil fuel-fired boilers in the non-EGU industries identified in section VI.C of this document that serve electricity generators and that qualify for an exemption from inclusion in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs to instead meet the same emissions standards, if any, that would apply under this rulemaking to fossil fuel-fired boilers at facilities in the same non-EGU industries that do not serve electricity generators.

Comment: Some stakeholders support the continued exclusion of qualifying cogenerators from the EGU program, but suggested they be regulated as non-EGUs if they don't fit the EGU applicability criteria.

Response: The EPA agrees that there is no basis within the four-step framework to exempt cogeneration units that fall under the applicability criteria of the final rule for non-EGU boilers simply because they are cogeneration units. While cogeneration units do have environmental benefits as noted at proposal, some cogeneration unit-types, particularly boilers, are estimated to have NO_X emissions that would otherwise meet this rule's criteria at Step 3 for constituting ''significant contribution.'' These units can meet the emissions limits that are otherwise finalized for these unit types, and the EPA does not find a basis to exclude them simply because they may have other environmentally-beneficial attributes.

These emissions limits are set forth in section VI.C.5 of this document. Therefore, the final requirements for non-EGUs do not exempt cogeneration units and any cogeneration emissions units meeting the applicability criteria for non-EGUs will be subject to the final emissions limits for the appropriate non-EGU emissions unit. Based on EPA's review of available data, across all of the non-EGU industries covered by this rule, there are four cogeneration boilers (two in Pulp and Papermill and two in Basic Chemical Manufacturing) that would meet the final rule's applicability criteria for non-EGU units and are included in the analysis of non-EGU emissions reduction potential in section V.C.2 of this document.

4. Mobile Source NO_X Mitigation Strategies

Under a variety of CAA programs, the EPA has established Federal emissions and fuel quality standards that reduce emissions from cars, trucks, buses, nonroad engines and equipment, locomotives, marine vessels, and aircraft (*i.e.,* ''mobile sources''). Because states are generally preempted from regulating new vehicles and engines with certain exceptions (*see generally* CAA section 209), mobile source emissions are primarily controlled through EPA's Federal programs. The EPA has been regulating mobile source emissions since it was established as a Federal agency in 1970, and all mobile source sectors are currently subject to NO_X emissions standards. The EPA factors these standards and associated emissions reductions into its baseline air quality assessment in good neighbor rulemaking, including in this final rule. These data are factored into EPA's analysis at Steps 1 and 2 of the 4-step framework. As a result of this long history, NO_X emissions from onroad and nonroad mobile sources have substantially decreased (73 percent and 57 percent since 2002, for onroad and nonroad, respectively) [227] and are predicted to continue to decrease into the future as newer vehicles and engines that are subject to the most recent, stringent standards replace older vehicles and engines.[228]

For example, in 2014, the EPA promulgated new, more stringent emissions and fuel standards for light-duty passenger cars and trucks.[229] The fuel standards took effect in 2017, and the vehicle standards phase in between 2017 and 2025. Other EPA actions that are continuing to reduce NO_X emissions include the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002; January 18, 2001); the Clean Air Nonroad Diesel Rule (69 FR 38957; June 29, 2004); the Locomotive and Marine Rule (73 FR 25098; May 6, 2008); the Marine Spark-Ignition and Small Spark-Ignition Engine Rule (73 FR 59034; October 8, 2008); the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895; April 30, 2010); and the Aircraft and Aircraft Engine Emissions Standards (77 FR 36342; June 18, 2012).

Most recently, EPA finalized more stringent emissions standards for NO_X and other pollution from heavy-duty trucks (Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards, 88 FR 4296, January 24, 2023). These standards will take effect beginning with model year 2027. Heavy-duty vehicles are the largest contributor to mobile source emissions of NO_X and will be one of the largest mobile source contributors to ozone in 2025.[230] Reducing heavy-duty vehicle emissions nationally will improve air quality where the trucks are operating as well as downwind. The EPA's existing regulatory program for mobile sources will continue to reduce NO_X emissions into the future.

Comment: The EPA received comments on ozone-precursor emissions from mobile sources, including cars, trucks, trains, ships, and planes. Commenters broadly encouraged the EPA to require emissions reductions from mobile sources in this rule. Commenters stated that the transportation sector plays a significant role in NO_X pollution and ozone formation and urged the EPA to finalize emissions reductions for the transportation sector that will enable attainment of the 2015 ozone NAAQS. Some commenters noted that high proportions of NO_X emissions in various upwind states are attributable to the transportation sector, and stated that EPA should have targeted emissions reductions from mobile sources first before requiring more stringent emissions controls from stationary sources in the same upwind states.

Response: The EPA agrees with commenters that a variety of sources, including mobile sources in the transportation sector, produce NO_X emissions that contribute to ozone air quality problems across the U.S. This rule, as with prior interstate transport actions, does not ignore those emissions, and it credits those on-the-books measures of states and the Federal Government within the four-step framework by including emissions and

[227] US EPA. Our Nation's Air: Status and Trends Through 2019. *https://gispub.epa.gov/air/trendsreport/2020/#home*.

[228] National Emissions Inventory Collaborative (2019). 2016v1 Emissions Modeling Platform. Retrieved from *http://views.cira.colostate.edu/wiki/wiki/10202*.

[229] Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emissions and Fuel Standards, 79 FR 23414 (April 28, 2014).

[230] Zawacki et al, 2018. Mobile source contributions to ambient ozone and particulate matter in 2025. Atmospheric Environment. Vol 188, pg 129–141. Available online: *https://doi.org/10.1016/j.atmosenv.2018.04.057*.

emissions reductions from these sources in the emissions inventory for air quality modeling, which informs Steps 1 and 2 of this analysis. Thus, this rule accurately represents emissions from mobile sources that are used to evaluate the contribution of states to ozone air quality problems in other states. See section IV.C of this document.

The EPA notes that its Step 3 analysis for this FIP does not assess additional emissions reductions opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing these emissions at the Federal level. EPA's various Federal mobile source programs, summarized above in this section, have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions from final rules are factored into the Agency's assessment of air quality and contributions at Steps 1 and 2. Further, states are generally preempted from regulating new vehicles and engines with certain exceptions, and therefore a question exists regarding the EPA's authority to address such emissions through such means when regulating in place of the states under CAA section 110(c). *See generally* CAA section 209. *See also* 86 FR 23099.[231] In any case, the existence of mobile source emissions noted by commenters does not lead to the conclusion that the EPA must require mobile source reductions in this rule or that the EPA has not properly identified "source[s] or other type[s] of emissions activity" in upwind states that "significantly contribute" for purposes of the Good Neighbor Provision. The EPA is committed to continuing the effective implementation and enforcement of current mobile source standards and continuing its efforts on new standards. The EPA will continue to work with state and local air agencies to incorporate emissions reductions from the transportation sector into required ozone attainment planning elements.

C. Control Stringencies Represented by Cost Threshold ($ per ton) and Corresponding Emissions Reductions

1. EGU Emissions Reduction Potential by Cost Threshold

For EGUs, as discussed in section V.A of this document, the multi-factor test considers increasing levels of uniform control stringency in combination with considering total NO_X reduction potential and corresponding air quality improvements. The EPA evaluated EGU NO_X emissions controls that are widely available (described previously in section V.B.1 of this document), that were assessed in previous rules to address ozone transport, and that have been incorporated into state planning requirements to address ozone nonattainment.

The EPA evaluated the EGU sources within the State of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies.[232] The EGUs in the state are sufficiently well-controlled resulting in the lowest fossil-fuel emissions rate and highest share of renewable generation among the 23 states examined at Step 3. EPA's Step 3 analysis, including analysis of the emissions reduction factors from EGU sources in the state, therefore resulted in no additional emissions reductions required to eliminate significant contribution from any EGU sources in California.

The following tables summarize the emissions reduction potentials (in ozone season tons) from these emissions controls across the affected jurisdictions. Table V.C.1–1 focuses on near-term emissions controls while Table V.C.1–2 includes emissions controls with extended implementation timeframes.

TABLE V.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2023

State	Baseline 2023 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion		
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades
Alabama	6,412	32	32	32
Arkansas	8,955	28	28	28
Illinois	7,721	70	70	247
Indiana	13,298	856	856	858
Kentucky	13,900	299	901	901
Louisiana	9,974	515	515	611
Maryland	1,214	0	0	8
Michigan	10,746	4	4	19
Minnesota	5,643	98	98	139
Mississippi	6,283	73	984	984
Missouri	20,094	7,339	7,339	7,497
Nevada	2,372	4	4	4
New Jersey	915	143	143	143
New York	3,977	64	64	64
Ohio	10,264	1,154	1,154	1,154
Oklahoma	10,470	199	890	890
Pennsylvania	8,573	336	336	436
Texas	41,276	909	909	1,142
Utah	15,762	7	7	7
Virginia	3,329	164	242	263
West Virginia	14,686	554	1,099	1,380

[231] This is not to say that states lack other options to reduce emissions from mobile sources. For example, a general list of types of transportation control measures can be found in CAA section 108(f). In addition, in accordance with section 177, states may (but are not required to) adopt California vehicle emissions standards for which a waiver has been granted from the preemption provisions in section 209(a). States that decide to adopt California vehicle emissions standards may also choose to submit those standards to be included as a part of their SIP.

[232] The only coal-fired power plant in California is the 63 MW Argus Cogeneration facility in Trona, California.

TABLE V.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2023—Continued

State	Baseline 2023 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion		
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades
Wisconsin	6,321	7	7	26
Total	222,184	12,854	15,681	16,832

*The EPA shows reduction potential from state-of-the-art LNB upgrade as near-term emissions controls, but explains in section V.B and VI.A of this document that this reduction potential would not be implemented until 2024.

TABLE V.C.1–2—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (TONS)—2026 *

State	Baseline 2026 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion			
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades + SCR/SNCR retrofits
Alabama	6,371	32	32	32	604
Arkansas	8,728	28	28	28	4,697
Illinois	6,644	70	70	230	1,281
Indiana	9,468	768	768	770	1,333
Kentucky	13,211	299	739	739	5,303
Louisiana	9,704	515	515	611	5,894
Maryland	901	51	51	59	59
Michigan	7,790	4	4	19	1,959
Minnesota	4,197	98	98	139	1,613
Mississippi	6,022	73	984	984	3,938
Missouri	18,612	7,339	7,339	7,497	11,231
Nevada	1,146	4	4	4	4
New Jersey	915	143	143	143	143
New York	3,977	64	64	64	589
Ohio	9,083	1,154	1,154	1,154	1,154
Oklahoma	10,259	199	890	890	5,968
Pennsylvania	8,362	352	352	452	1,204
Texas	39,684	909	909	1,142	15,980
Utah	9,930	7	7	7	7,338
Virginia	3,019	164	242	263	646
West Virginia	13,185	401	947	1,227	3,507
Wisconsin	5,016	7	7	26	623
Total	196,225	12,680	15,346	16,480	75,067

*The EPA shows all emissions reduction potential identified for assumed SCR retrofits in the Step 3 analytic year 2026, but explains in sections V.B and VI.A of this document that for Step 4 implementation this emissions reduction potential will be phased in during the 2026 and 2027 ozone season control periods.

2. Non-EGU or Industrial Source Emissions Reduction Potential

As described in the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' the EPA uses the 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the CMDB, to estimate NO_X emissions reductions and costs for the year 2026. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from and costs to meet the final rule emissions limits may also differ from those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

Table V.C.2–1 summarizes the industries, estimated emissions unit types, assumed control technologies, estimated annual costs (2016$), and estimated ozone season emissions reductions in 2026, and Table V.C.2–2 summarizes the estimated reductions by state.

TABLE V.C.2–1—BY INDUSTRY IN 2026, ESTIMATED EMISSIONS UNIT TYPES, ASSUMED CONTROL TECHNOLOGIES, ANNUAL COSTS (2016$), AND ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS)

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Annual costs (2016$)	Ozone season emissions reductions
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	385,463,197	32,247
Cement and Concrete Product Manufacturing.	Kiln	SNCR	10,078,205	2,573
Iron and Steel Mills and Ferroalloy Manufacturing.	Reheat Furnaces	LNB	3,579,294	408
Glass and Glass Product Manufacturing	Furnaces	LNB	7,052,088	3,129
Iron and Steel Mills and Ferroalloy Manufacturing.	Boilers	SCR, LNB + FGR	8,838,171	440
Metal Ore Mining			621,496	18
Basic Chemical Manufacturing			49,697,848	1,748
Petroleum and Coal Products Manufacturing.			5,128,439	147
Pulp, Paper, and Paperboard Mills			62,268,540	1,836
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	38,949,560	2,071
Totals			571,676,839	44,616

TABLE V.C.2–2—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS) BY UPWIND STATE IN 2026

State	2019 OS emissions *	OS NO_X reductions
AR	8,790	1,546
CA	16,562	1,600
IL	15,821	2,311
IN	16,673	1,976
KY	10,134	2,665
LA	40,954	7,142
MD	2,818	157
MI	20,576	2,985
MO	11,237	2,065
MS	9,763	2,499
NJ	2,078	242
NV [233]	2,544	0
NY	5,363	958
OH	18,000	3,105
OK	26,786	4,388
PA	14,919	2,184
TX	61,099	4,691
UT	4,232	252
VA	7,757	2,200
WV	6,318	1,649
Totals	302,425	44,616

* The 2019 OS season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

In Table V.C.2–3 by industry and emissions unit type, the EPA provides a summary of the control technologies applied and their average costs across all of the non-EGU emissions units. The average cost per ton values range from $939 to $14,595 per ton. Note that the average cost per ton values are in 2016 dollars and reflect simple averages and not a percentile or other representative cost values from a distribution of cost estimates.

TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	4,981
Cement and Concrete Product Manufacturing	Kiln	SNCR	1,632

[233] We are not aware of existing non-EGU emissions units in Nevada that meet the applicability criteria for non-EGUs in the final rule. If any such units in fact exist, they would be subject to the requirements of the rule just as in any other state. In addition, any new emissions unit in Nevada that meets the applicability criteria in the final rule will be subject to the final rule's requirements. *See* section III.B.1.d.

TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS—Continued

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3,656
Glass and Glass Product Manufacturing	Furnaces	LNB	939
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR or LNB + FGR	8,369
Metal Ore Mining			14,595
Basic Chemical Manufacturing			11,845
Petroleum and Coal Products Manufacturing			14,582
Pulp, Paper, and Paperboard Mills			14,134
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	7,836
Overall Average Cost/Ton			5,339

Refer to the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs'' for additional estimates—including by industry and by state. These estimates are proxy estimates, and the EPA also did not prepare detailed engineering analyses for the industries, facilities, and individual emissions units identified for the final rule. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from and costs to meet the final rule emissions limits may also differ from those estimated in this assessment.

Comment: Regarding the marginal cost threshold of $7,500/ton used to assess potential emissions reductions in the non-EGU screening assessment prepared for proposal, commenters raised a range of questions, including (1) why the EPA used a marginal cost threshold that is much higher than the $2,000/ton threshold used in the 2021 Revised CSAPR Update Rule, (2) why the EPA used a ''one size fits all'' approach for addressing the estimated cost and actual emissions reductions achievable, particularly for existing sources of NO_X emissions, (3) why the EPA set a $7,500/ton marginal cost threshold for all non-EGUs, despite acknowledging the heterogeneity of industry, emissions unit types and control options and failing to consider the actual costs associated with achieving the proposed reductions at different types of emissions units in order to artificially inflate the marginal cost threshold and to justify otherwise cost-prohibitive NO_X control technologies. Commenters also stated that controls for their industry are not cost-effective using the EPA's presumptive value of $7,500/ton and that the value may not be technically feasible to apply to existing sources that would have to retrofit controls.

Response: The EPA notes that the primary purpose of the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (non-EGU screening assessment) was to identify potentially impactful industries and emissions unit types for further evaluation.[234] In the non-EGU screening assessment memorandum we presented an analytical framework to further analyze potential emissions reductions and costs and included proxy estimates for 2026.

As noted in section V.D. of this document, at proposal the EPA found that based on data available at that time and for the purposes of the non-EGU screening assessment, it appeared that a $7,500 marginal cost-per-ton threshold could be used as a proxy to identify cost-effective emissions control opportunities. Also, the $7,500 marginal cost-per-ton threshold is higher than the cost-per-ton value used in the Revised Cross-State Air Pollution Rule Update because that rulemaking assessed significant contribution for the less protective 2008 ozone NAAQS, and it is reasonable when assessing significant contribution associated with the more protective 2015 ozone NAAQS, that a potentially more costly universe of emissions controls and related potential reductions should be included in the analysis.[235] Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. The EPA's potential cost threshold for non-EGU controls at proposal was intended to serve a similar representative purpose. Based on the EPA's updated analysis for this final rule, the EPA recognizes that the $7,500/ton threshold does not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed.

While the potentially impactful industries (identified in Step 1 of the analytical framework presented in the non-EGU screening assessment) were directly used, the proxy estimates for emissions unit types, emissions reductions, and costs from the non-EGU screening assessment were not directly used to establish applicability thresholds and emissions limits in the proposal. To further evaluate the impactful industries and emissions unit types and establish the proposed emissions limits, the EPA reviewed RACT rules, NSPS rules, NESHAP rules, existing technical studies (*e.g.,* Ozone Transport Commission, Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions, October 17, 2012), rules in approved SIP submittals, consent decrees, and permit limits.[236]

[234] The non-EGU screening assessment memorandum is available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0150.*

[235] As the amount of air pollution that is allowed in the ambient air is reduced (i.e., when a NAAQS is revised), it is reasonable to expect that further emissions reductions may be necessary to bring areas into attainment with that more protective standard. At the same time, the available remaining emissions reduction opportunities will likely have become more costly compared to a prior period, because other CAA requirements, including such as earlier transport rules, will have consumed those emissions reduction opportunities that were the least costly. The EPA noted this same possibility in the original CSAPR rulemaking, *see* 76 FR 48210.

[236] This review is detailed in the Final Non-EGU Sectors TSD available in the docket here: *https://www.regulations.gov/document/EPA-HQ-OAR-2021-0668-0145.*

D. Assessing Cost, EGU and Non-EGU NO_X Reductions, and Air Quality

To determine the emissions that are significantly contributing to nonattainment or interfering with maintenance, the EPA applied the multi-factor test to EGUs and non-EGUs separately, considering for each the relationship of cost, available emissions reductions, and downwind air quality impacts. Specifically, for each sector, the EPA finalizes a determination regarding the appropriate level of uniform NO_X control stringency that would collectively eliminate significant contribution to downwind nonattainment and maintenance receptors. Based on the air quality results presented in this section, we find that the emissions control strategies that were identified and evaluated in sections V.B and V.C of this document and found to be both cost-effective and feasible, deliver meaningful air quality benefits through projected reductions in ozone levels across the linked downwind nonattainment and maintenance receptors in the relevant analytic years 2023 and 2026. Further, EPA finds the emissions control strategies in upwind states that would deliver these benefits to be widely available and in use at many other similar EGU and non-EGU facilities throughout the country, particularly in those areas that have historically or now continue to struggle to attain and maintain the 2015 ozone NAAQS. Applying these emissions control strategies on a uniform basis across all linked upwind states continues to constitute an efficient and equitable solution to the problem of allocating upwind-state responsibility for the elimination of significant contribution. This approach continues to effectively address the ''thorny'' causation problem of interstate pollution transport for regional-scale pollutants like ozone that transport over large distances and are affected by the vagaries of meteorology. *EME Homer City,* 572 U.S. at 514–16. It requires the most impactful sources in each state that has been found to contribute to ozone problems in other states to come up to minimum standards of environmental performance based on demonstrated NO_X pollution-control technology. *Id.* at 519. When the effects of these emissions reductions are assessed collectively across the hundreds of EGU and non-EGU industrial sources that are subject to this rule, the cumulative improvements in ozone levels at downwind receptors, while they may vary to some extent, are both measurable and meaningful and will assist downwind areas in attaining and maintaining the 2015 ozone NAAQS.

In addition to the findings of cost-effectiveness, feasibility and widespread availability that support EPA's identification of the appropriate level of emissions-control stringency at Step 3 discussed in sections V.B and V.C, the findings regarding air quality improvement in this section—as in prior transport rules—are a central component of our Step 3 analytic findings as to the definition of ''significant contribution.'' EPA's assessment of air quality improvement for all of the emissions control strategies included shows continued air quality improvement with each additional control strategy measure. Within the group of selected control strategies for EGUs and non-EGUs no clear ''knee-in-the-curve'' is evident; *i.e.,* there is no point at which there is a noticeable decline in the rate of air quality improvement up through the control stringency level selected. However, if EPA were to go beyond the selected control stringency through inclusion of additional EGU or non-EGU NO_X mitigation technologies for the covered sources and unit-types that are, at least on the record of this action, not widely available, uncertain or untested, and/or far more costly, a ''knee-in-the-curve'' does materialize, where the incremental air quality benefit per dollar spent per ton on mitigation measures plateaus even as costs increase dramatically. In the Revised CSAPR Update, EPA explained that a knee in the curve ''is not on its own a justification for not requiring reductions beyond that point,'' 86 FR 23107, but does indicate that it is a useful indicator for informing potential stopping points. The observation that no ''knee-in-the-curve'' materializes at the stringency levels up through that selected by EPA supports EPA's identified control stringency.

Further, as the Supreme Court has explained, ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' 572 U.S. at 523. While the ultimate purpose of the good neighbor provision is to eliminate significant contribution and not necessarily to resolve downwind areas' nonattainment and maintenance problems, we have evaluated the expected attainment status at each identified receptor as we examine the air quality effects of the different emissions control strategies identified. As discussed further in this section, the EPA notes that multiple receptors shift into projected attainment status or shift from projected nonattainment to maintenance status up through the stringency level ultimately selected by EPA. (And all receptors show improvement in air quality even if their status does not change.) These analytic findings at Step 3 cement EPA's identification of the selected EGU and non-EGU mitigation measures as the appropriate control stringency to fulfill its statutory obligation to eliminate significant contribution for the 2015 ozone NAAQS for the covered states. The EPA also evaluated whether the final rule resulted in possible over-control scenarios by evaluating if an upwind state is linked solely to downwind air quality problems that could have been resolved at a lower cost threshold, or if an upwind state could have reduced its emissions below the 1 percent of NAAQS air quality contribution threshold at a lower cost threshold. The Agency finds no overcontrol from this rule. See section V.D.4 of this document.

1. EGU Assessment

For EGUs, the EPA examined the emissions reduction potential associated with each EGU emissions control technology (presented in section V.C.1 of this document) and its impact on the air quality at downwind receptors. Specifically, EPA identified and assessed the projected average air quality improvements relative to the base case and whether these improvements are sufficient to shift the status of receptors from projected nonattainment to maintenance or from maintenance to attainment. Combining these air quality factors, costs, and emissions reductions, the EPA identified a control stringency for EGUs that results in substantial air quality improvement from emissions controls that are available in the timeframe for which air quality problems at downwind receptors persist. For all affected jurisdictions, this control stringency reflects, at a minimum, the optimization of existing post-combustion controls and installation of state-of-the-art NO_X combustion controls, which are widely available at a representative cost of $1,800 per ton. EPA's evaluation also shows that the effective emissions rate performance across affected EGUs consistent with realization of these mitigation measures does not over-control upwind states' emissions relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS.

Similarly, the EPA also identified installation of new SCR post-combustion controls at coal steam sources greater than or equal to 100 MW and for a more limited portion of the oil/gas steam fleet that had higher levels of emissions as components of the required control stringency. These SCR retrofits are widely available starting in the 2026 ozone season at $11,000 and $7,700 per ton respectively. For all but 3 of the affected states (Alabama, Minnesota, and Wisconsin, which are no longer linked in 2026 at Steps 1 and 2 in EPA's base case air quality modeling for this final rule), EPA's evaluation shows that the effective emissions rate performance across EGUs consistent with the full realization of these mitigation measures does not over-control upwind states' emissions in 2026 relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS (*see* the Ozone Transport Policy Analysis Final Rule TSD for details).

To assess downwind air quality impacts for the nonattainment and maintenance receptors identified in section IV.D of this document, the EPA evaluated the air quality change at that receptor expected from the progressively more stringent upwind EGU control stringencies that were available for that time period in upwind states linked to that receptor. This assessment provides the downwind ozone improvements for consideration and provides air quality data that is used to evaluate potential over-control situations.

To assess the air quality impacts of the various control stringencies at downwind receptors for the purposes of Step 3, the EPA evaluated changes resulting from the emissions reductions associated with the identified emissions controls in each of the upwind states, as well as assumed corresponding reductions of similar stringency in the downwind state containing the receptor to which they are linked. By applying these emissions reductions to the state containing the receptor, the EPA assumes that the downwind state will implement (if it has not already) an emissions control stringency for its sources that is comparable to the upwind control stringency identified here. Consequently, the EPA is accounting for the downwind state's ''fair share'' of the responsibility for resolving a nonattainment or maintenance problem as a part of the over-control evaluation.[237]

For this assessment, the EPA used an ozone air quality assessment tool (ozone AQAT) to estimate downwind changes in ozone concentrations related to upwind changes in emissions levels. The EPA focused its assessment on the years 2023 and 2026 as they pertain to the last years for which ozone season emissions data can be used for purposes of determining attainment for the Moderate (2024) and Serious (2027) attainment dates. For each EGU emissions control technology, the EPA first evaluated the magnitude of the change in ozone concentrations at the nonattainment and maintenance receptors for each relevant year (*i.e.,* 2023 and 2026). Next, the EPA evaluated whether the estimated change in concentration would resolve the receptor's nonattainment or maintenance concern by lowering the average or maximum design values, respectively, below 71 ppb. For a complete set of estimates, see the Ozone Transport Policy Analysis Final Rule TSD or the ozone AQAT Excel file.

For 2023, the EPA evaluated potential air quality improvements at the downwind receptors outside of California associated with available EGU emissions control technologies in that timeframe. The EPA determined for the purposes of Step 3 that the average air quality improvement at the receptors relative to the engineering analytics base case was 0.06 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs and combustion control upgrades. The EPA determined for the purposes of Step 3 that no receptors switch from maintenance to attainment or from nonattainment to maintenance with these mitigation strategies in place. Table V.D.1–1 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT.

For 2026, the EPA determined that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.47 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, and new post-combustion control (SCR and SNCR) retrofits at eligible units are assumed to be implemented. The EPA determined for the purposes of Step 3 that in 2026, all but one of the receptors are expected to remain nonattainment or maintenance across these control stringencies, with one receptor in Larimer County, Colorado (Monitor 080690011), switching from maintenance to attainment and two receptors (one in Fairfield County, Connecticut (Monitor 90013007), and one in Galveston, Texas (Monitor ID 481671034)) switching from nonattainment to maintenance with these mitigation strategies in place.[238] Table V.D.1–2 summarizes the results of EPA's Step 3 evaluation of air quality improvements at the receptors included in the AQAT analysis. For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Final Rule TSD and to the Ozone AQAT included in the docket for this rule.

[237] For EGUs, this analysis for the Connecticut receptors shows no EGU reduction potential in Connecticut from the emissions reduction measures identified given that state's already low-emitting fleet; however, EGU reductions were identified in Colorado and these reductions were included in the over-control analysis.

[238] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. This method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states action are further discussed in sections V.D.3 and V.D.4 of this document.

TABLE V.D.1–1—AIR QUALITY AT THE RECEPTORS IN 2023 FROM EGU EMISSIONS CONTROL TECHNOLOGIES [a]

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade
40278011	Arizona	Yuma	70.36	70.34	72.05	72.04
80350004	Colorado	Douglas	71.12	71.10	71.71	71.70
80590006	Colorado	Jefferson	72.63	72.61	73.32	73.31
80590011	Colorado	Jefferson	73.29	73.27	73.89	73.87
80690011	Colorado	Larimer	70.79	70.78	71.99	71.98
90010017	Connecticut	Fairfield	71.62	71.56	72.22	72.16
90013007	Connecticut	Fairfield	72.99	72.90	73.89	73.80
90019003	Connecticut	Fairfield	73.32	73.25	73.62	73.55
90099002	Connecticut	New Haven	70.61	70.51	72.71	72.61
170310001	Illinois	Cook	68.13	68.11	71.82	71.80
170314201	Illinois	Cook	67.92	67.88	71.41	71.37
170317002	Illinois	Cook	68.47	68.37	71.27	71.17
350130021	New Mexico	Dona Ana	70.83	70.82	72.13	72.12
350130022	New Mexico	Dona Ana	69.73	69.72	72.43	72.42
350151005	New Mexico [b]	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	70.59	70.52	72.69	72.62
481210034	Texas	Denton	69.93	69.88	71.73	71.68
481410037	Texas	El Paso	69.82	69.81	71.43	71.41
481671034	Texas	Galveston	71.82	71.70	73.13	73.01
482010024	Texas	Harris	75.33	75.25	76.93	76.85
482010055	Texas	Harris	71.19	71.10	72.20	72.10
482011034	Texas	Harris	70.32	70.25	71.52	71.45
482011035	Texas	Harris	68.01	67.94	71.52	71.45
490110004	Utah	Davis	71.88	71.87	74.08	74.07
490353006	Utah	Salt Lake	72.48	72.47	74.07	74.06
490353013	Utah	Salt Lake	73.21	73.20	73.71	73.70
550590019	Wisconsin	Kenosha	70.75	70.65	71.65	71.55
551010020	Wisconsin	Racine	69.59	69.46	71.39	71.25
551170006	Wisconsin	Sheboygan	72.64	72.46	73.54	73.36
Average AQ Change Relative to Base (ppb)						0.06
Total PPB Change Across All Receptors Relative to Base [c]						1.58

Table Notes:

[a] The EPA notes that the design values reflected in tables V.D.1–1 and –2 correspond to the engineering analysis EGU emissions inventory that was used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Final Rule TSD.

[b] New Mexico Eddy and Lea monitors have no values in tables V.D.1–1 and 1–2 as EPA does not have calibration factors for these monitors as no contributions were calculated for them from the proposal AQ modeling

[c] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section VIII of this document provides a more complete picture of the air quality impacts of the final rule.

TABLE V.D.1–2—AIR QUALITY AT RECEPTORS IN 2026 FROM EGU EMISSIONS CONTROL TECHNOLOGIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit
40278011	Arizona	Yuma	69.87	69.84	71.47	71.44
80590006	Colorado	Jefferson	71.70	71.36	72.30	71.95
80590011	Colorado	Jefferson	72.06	71.59	72.66	72.19
80690011	Colorado	Larimer	69.84	69.54	71.04	70.73
90013007	Connecticut	Fairfield	71.25	70.98	72.06	71.78
90019003	Connecticut	Fairfield	71.58	71.34	71.78	71.54
350130021	New Mexico	Dona Ana	70.06	69.89	71.36	71.19
350130022	New Mexico	Dona Ana	69.17	69.00	71.77	71.60
350151005	New Mexico	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	69.89	68.96	72.02	71.06
481671034	Texas	Galveston	71.29	70.02	72.51	71.22
482010024	Texas	Harris	74.83	73.86	76.45	75.46
490110004	Utah	Davis	69.90	69.34	72.10	71.52
490353006	Utah	Salt Lake	70.50	69.96	72.10	71.55
490353013	Utah	Salt Lake	71.91	71.45	72.31	71.84
551170006	Wisconsin	Sheboygan	70.83	70.51	71.73	71.41
Average AQ Change Relative to Base (ppb)						0.47
Total PPB Change Across All Receptors Relative to Base (ppb)						7.04

Figures 1 and 2 to section V.D.1 of this document, included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD available in the docket for this rulemaking, illustrate the air quality improvement relative to the estimated representative cost associated with the previously identified emissions control technologies. The graphs show improving air quality at the downwind receptors as emissions reductions commensurate with the identified control technologies are assumed to be implemented. Figure 1 to section V.D.1 of this document reflects emissions reductions commensurate with optimization of existing SNCRs and SCRs. Figure 2 to section V.D.1 of this document reflects emissions reductions commensurate with installation of new post combustion controls (mainly SCRs) layered on top of the emissions reduction potential from the technologies represented in Figure 1 to section V.D.1 of this document. The graphic, and underlying AQAT receptor-by-receptor analysis demonstrates that air quality continues to improve at downwind receptors as EPA examines increasingly stringent EGU NO_X control technologies. While all major technology breakpoints identified in sections V.B and V.C of this document show continued air quality improvements at problematic receptors and at cost and technology levels that are commensurate with mitigation strategies that are proven to be widely available and implemented, EPA's quantification and application of those breakpoints reflect certain exclusions to: (1) preserve this consistency with widely observed mitigation measures in states, and (2) remove any retrofit assumptions at marginal units that would have much higher dollar per ton representative cost and little or no air quality benefit. For instance, the EPA does not define the SCR retrofit breakpoint ($11,000 per ton) to include retrofit application at steam units less than 100 MW or at oil/gas steam units emitting at less than 150 tons per ozone season. The emissions reductions from these potential categories of measures are small and do not constitute additional ''breakpoints'' in EPA's estimation. They would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. This careful calibration of technology breakpoints through exclusion of measures that are clearly not cost-effective in terms of air quality benefit allows for the identification of an EGU uniform control stringency that is an appropriate reflection of those readily available and widely implemented emissions reduction strategies that will have meaningful downwind air quality impact.

Moreover, these technologies (and representative cost) are demonstrated ozone pollution mitigation strategies that are widely practiced across the EGU fleet and are of comparable stringency to emissions reduction measures that many downwind states have already instituted. The coal SCR retrofit measures driving the majority of the emissions reductions in this action not only reflect industry best practice, but they also reflect prevailing practice among EGUs. More than 66 percent of the existing coal capacity already has this technology in place. For nearly 25 years, all new coal-fired EGUs that commenced construction have had SCR (or equivalent emissions rates). The 1997 proposed amendments to subpart Da revised the NO_X standard based on the use of SCR. The NO_X SIP Call (promulgated in 1998) established emissions reduction requirements premised on extensive SCR installation (142 units) and incentivized well over 40 GWs of SCR retrofit in the ensuing years.[239] Similarly, the Clean Air Interstate Rule established emissions reductions requirements in 2006 that assumed SCR would be installed on another 58 units (15 GW) in the ensuing years among just 10 states, and an even greater volume of capacity chose SCR retrofit measures in the wake of finalizing that action.[240]

Basing emissions reduction requirements for EGUs on SCR retrofits is also consistent with regulatory approaches adopted by states, which—particularly in downwind areas more impacted by ozone transport contribution from upwind state emissions—have already adopted SCR-based standards as part of stringent NO_X control programs. Regulatory programs that impose stringent RACT requirements on all major power plants and Lowest Achievable Emission Rate (LAER) standards on all new major sources of NO_X have resulted in remaining coal-fired generating resources in states along the Northeast Corridor such as Connecticut, Delaware, New Jersey, New York, and Massachusetts all being retrofitted with SCR.[241] The Maryland Code of Regulations requires coal-fired sources to operate existing SCR controls or install SCR controls by specified dates.[242] Programs like North Carolina's Clean Smokestacks Act and Colorado's Clean Air, Clean Jobs Act have also required or prompted SCR retrofits on units.[243] Unit-level BART requirements for the first Regional Haze planning period also determined SCR retrofits (and corresponding emissions rates) were cost-effective controls for a variety of sources in the U.S.[244]

As shown in Figure 1 to section V.D.1 of this document,[245] the majority of EGU emissions reduction potential and associated air quality improvements estimated for 2023 occurs from optimization of existing SCRs, with some additional reductions from installation of state-of-the-art combustion controls at the same representative cost threshold. At the slightly higher representative cost threshold of $1,800 per ton, there is some additional air quality improvement from optimization of existing SNCRs. These measures taken together represent the control stringency at which near-term incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the near-term emissions control technologies are available at reasonable cost and that these reductions provide meaningful improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors. Figure 1 to section V.D.1 of this document [246] highlights (1) the continuous connection between identified emissions reduction potential and downwind air quality improvement across the range of near-term mitigation measures assessed, and (2) the cost-effective availability of these reductions and corresponding air quality improvements.

Additional considerations that are unique to EGUs provide additional support for EPA's determination to include SCR and SNCR optimization as part of the identified near-term control stringency, including:

[239] 63 FR 57448.

[240] 71 FR 25345.

[241] EPA–HQ–OAR–2020–0272. Comment letter from Attorneys General of NY, NJ, CT, DE, MA.

[242] COMAR 26.11.38 (control of NO_X Emissions from Coal-Fired Electric Generating Units).

[243] *https://www.epa.gov/system/files/documents/2021-09/table-3-30-state-power-sector-regulations-included-in-epa-platform-v6-summer-2021-refe.pdf.*

[244] *See* table 3–35 BART regulations in EPA IPM documentation available at *https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.*

[245] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

[246] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

• these controls are already installed and available for operation on these units;
• they are on average already partially operating, but not necessarily optimized;
• the reductions are available in the near-term (during ozone seasons when the problematic receptors are projected to persist), including by the 2023 ozone season aligned with the Moderate area attainment date; and
• these sources are already covered under the existing CSAPR NO_X Ozone Season Group 2 or Group 3 Trading Programs or the Acid Rain Program and thus have the monitoring, reporting, recordkeeping, and all other necessary elements of compliance with the trading program already in place.

The majority of EGU emissions reduction potential and associated air quality improvements estimated to start in 2026 occur from retrofitting uncontrolled steam sources with post-combustion controls. At the representative cost threshold of $11,000 per ton, there are significant additional air quality improvements from emissions reductions commensurate with installation of new SCRs and SNCRs. These measures taken together with the near-term emissions reduction measures described previously represent the level of control stringency in 2026 at which incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the emissions control technologies are available at reasonable cost and that these reductions can provide improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors.

The EPA finds that the control stringency that reflects optimization of existing SCRs and SNCRs, installation of state-of-the-art combustion controls, and the retrofitting of new post combustion controls at the coal and oil/gas steam capacity described previously is projected to result in nearly 73,000 tons of NO_X reduction (approximately 40 percent of the 2026 baseline level) for the 19 linked states in 2026 subject to a FIP for EGUs, which will deliver notable air quality improvements across all transport-impacted receptors and assist in fully resolving one downwind air quality receptor for the 2015 ozone NAAQS. Figure 2 to section V.D.1 of this document[247] demonstrates the continuous connection between identified emissions reduction potential and downwind air quality improvement across the range of mitigation measures assessed in 2026. At no point do the additional emissions mitigation measures examined here fail to produce corresponding downwind air quality improvements.

The EPA is determining that the appropriate EGU control stringency is commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades for those states linked to downwind nonattainment or maintenance receptors in 2023. For those states also linked in 2026, the EPA is determining that the appropriate EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam units of 100 MW or greater capacity (excepting circulating fluidized bed units), new SNCR on coal steam units of less than 100 MW capacity and circulating fluidized bed units, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

As noted previously in section V.B of this document and in the EGU NO_X Mitigation Strategies Final Rule TSD, the EPA considered other methods of identifying mitigation measures (*e.g.,* SCRs on smaller units, combustion control upgrades on combustion turbines, SCRs on combined cycle and simple cycle combustion turbines). The emissions reductions from these potential categories of measures do not constitute additional ''technology breakpoints'' in EPA's estimation, but rather reflect a different tier of assessment where further mitigation measures are based on inclusion of smaller and/or different generator-type units (rather than different pollution control technologies). Emissions reductions from these measures are relatively small and would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. Although these additional measures are not included in EPA's technology breakpoint analysis discussed in this section, the EPA did analyze the cost, potential reductions, and air quality impact of these additional measures to affirm that they do not merit inclusion in the final stringency for this action. That analysis shows the potential emissions reductions and air quality improvements from these additional measures occur beyond a notable ''knee-in-the-curve'' breakpoint. In other words, there are very little additional emissions reductions and air quality improvement at problematic receptors, and the cost associated with these measures increases substantially on a dollar per ton basis. The graphic capturing this effect (located in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD) illustrates the significant decline in cost-effectiveness of reductions if these measures had been included in EPA's final stringency.[248]

2. Non-EGU Assessment

Using a 2019 emissions inventory, the list of emissions units estimated to be captured by the applicability criteria, the assumed control technologies that would meet the emissions limits, and information on control efficiencies and default cost/ton values from the control measures database, the EPA estimated NO_X emissions reductions and costs for the year 2026. Given the EPA's conclusion that the 2026 ozone season is the earliest date by which the required controls can be installed across the identified non-EGU industries, the EPA assessed the effects of these controls in 2026 under its multi-factor test. In the assessment, we matched emissions units by Source Classification Code (SCC) from the inventory to the applicable control technologies in the CMDB. We modified SCC codes as necessary to match control technologies to inventory records. For additional details about the steps taken to estimate emissions units, emissions reductions, and costs, see the memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs'' available in the docket. The estimates using the 2019 inventory and information from the CMDB identify proxies for emissions units, as well as emissions reductions, and costs associated with the assumed control

[247] Included in Appendix I of the Ozone Transport Policy Analysis Final Rule TSD, which is available in the docket for this rulemaking.

[248] This is not to discount the potential effectiveness of these or other NO_X mitigation strategies outside the context of this rulemaking, which addresses regional ozone transport on a nationwide basis based on the present record. States and local jurisdictions may find such measures particularly impactful or necessary in the context of local attainment planning or other unique circumstances. Further, while the EPA finds on the present record that this rule is a complete remedy to the problem of interstate transport for the 2015 ozone NAAQS for the covered states, the EPA has in the past recognized that circumstances may arise after the promulgation of remedies under CAA section 110(a)(2)(D)(i)(I) in which the exercise of further remedial authority against specific stationary sources or groups of sources under CAA section 126 may be warranted. *See* Response to Clean Air Act Section 126(b) Petition From Delaware and Maryland, 83 FR 50444, 50453–54 (Oct. 5, 2018).

technologies that would meet the final emissions limits. Emissions units subject to the final rule emissions limits may differ from those estimated in this assessment, and the estimated emissions reductions from, and costs to meet, the final rule emissions limits may also differ from those estimated in this assessment. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

After reviewing public comments and updating some of the data used to provide an accurate assessment of the likely potential emissions reductions that could be achieved from the identified emissions units in the industries analyzed for proposal, the EPA finds that in general, these emissions reductions (with some modifications from proposal) are necessary to eliminate significant contribution at Step 3. The EPA's use of the analytical framework presented in the non-EGU screening assessment to identify potentially impactful industries and emissions unit types in the proposal remains valid. The EPA's criteria were intended to identify industries and emissions unit types that on a broad scale impact multiple receptors to varying degrees. The EPA focused its non-EGU screening assessment on (1) emissions and potential emissions reductions from these industries and emissions units and (2) the potential impact that emissions reductions from those industries and emissions units could deliver to the receptors.

While commenters criticized the analytical framework in the non-EGU screening assessment for assuming potentially unachievable emissions reductions at Step 3, or for not corresponding to a precise list of emissions units that would be covered at Step 4, these comments did not offer an alternative methodology for the Step 3 analysis to identify those industries and emissions units that potentially have the greatest impact and therefore should be scrutinized more closely for emissions reduction opportunities.[249] Further, contrary to some commenters' assertions, the EPA's assessment did not result in an unbounded scope of regulation of industrial sources. Of the approximately 40 industries defined by North American Industry Classification System codes the EPA analyzed, only seven industries were identified as having emissions and potential emissions reduction opportunities that met the EPA's air quality criteria for further assessment.

At proposal, the EPA found that based on data available at that time and for the purposes of the screening assessment, it appeared that a $7,500 marginal cost-per-ton threshold could be used as a proxy to identify cost-effective emissions control opportunities. Similar to the role of cost-effectiveness thresholds the EPA uses at Step 3 to evaluate EGU emissions control opportunities, this threshold is not intended to represent the maximum cost any facility may need to expend but is rather intended to be a representative figure for evaluating technologies to allow for a relative comparison between different levels of control stringency. For example, in the EGU analysis, the $11,000/ton average cost threshold for an SCR retrofit represents a range of SCR retrofit costs for units for which the 90th percentile cost-per-ton is roughly $21,000. See section V.B.a of this document. The EPA's potential cost threshold for non-EGU controls at proposal was intended to serve a similar representative purpose. We respond briefly to comments regarding the use of the $7,500/ton threshold in section V.C of this document. Comments regarding the screening assessment are further addressed in section 2.2 of the response to comments document in the docket.

Based on the EPA's updated analysis for this final rule, the EPA recognizes that the $7,500/ton threshold does not reflect the full range of cost-effectiveness values that are likely present across the many different types of non-EGU industries and emissions units assessed. However, the EPA nonetheless finds that, with some adjustments from proposal, the overall mix of emissions controls it identified at proposal is appropriate to eliminate significant contribution to nonattainment or interference with maintenance in downwind areas. In the final analysis, we find that the average cost-per-ton of emissions reductions across all non-EGU industries in this rule generally ranges from approximately $939/ton to $14,595/ton, with an overall average of approximately $5,339/ton. *See* memorandum titled ''Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,'' available in the docket.

Nonetheless, overall the EPA finds that the range of cost-effectiveness values for non-EGU industries and emissions units compares favorably with the values used to evaluate EGUs. As discussed in the preceding paragraphs, the representative cost for EGUs to retrofit SCR is $11,000/ton. This reflects a range of cost estimates, with $20,900/ton reflecting the 90th percentile of units (see section V.B.a of this document). The higher end of the estimated average cost range for certain non-EGU industrial emissions units is also in that range. While specific emissions units may have higher costs associated with installing pollution control technologies than other similar unit types, this does not in itself undermine the Agency's conclusion that a level of emissions control associated with a specific emissions limit or control technology is appropriate to require across the linked upwind state region, in light of the overall emissions reductions and air quality benefits at downwind receptors that those controls are projected to deliver.

We note that the non-EGU control cost estimates in this final rule were based on historical actual emissions. This can affect the presentation of cost-per-ton values at the unit level, and it would not be appropriate to abandon uniform control stringency among like units in the covered industries across or within upwind states based on such cost differentials.

The EPA finds it appropriate to require a uniform level of emissions control across similar emissions unit types to, among other things, prevent two potential outcomes related to shifting production, either between units within the same facility or between units at different facilities. First, if some units were exempted from control requirements because of historically low actual emissions, there is a risk that source owners or operators may shift production to these specific units, increasing their utilization and resulting in emissions increases from these units. Second, if some owners or operators were able to avoid the control requirements of the final rule on this basis, they could gain a competitive advantage vis-à-vis other facilities within their respective industries. Production could shift from units at another facility subject to the control requirements to the units that avoided control requirements (and thus avoid costs the regulated facility should bear), potentially resulting in emissions increases. The effect of such an approach in such circumstances would be mere emissions shifting rather than the elimination of significant

[249] For example, while the EPA has found it appropriate to limit the scope of emissions units that would be subject to emissions limits and controls in the iron and steel industry in light of comments regarding certain sources' inability to meet the EPA's proposed emission limits, this does not alter the EPA's determination that this industry is an impactful industry and that certain emissions controls should still be required.

contribution. Finally, as we have explained in prior transport actions, the cost-effectiveness figure is not the only factor that the agency considers at Step 3, *see* 86 FR 23073, and if used in isolation to make a policy decision without considering other information, could produce a result that is inconsistent with the objective of ensuring significant contribution is eliminated.[250]

In addition to our evaluation of cost-effectiveness on a cost per ton basis, the EPA's determination at Step 3 for non-EGUs is also informed by the overall level of emissions reductions that will be achieved across the region and the effect those reductions are projected to have on air quality at the downwind receptors (discussed more later in this section). We are also influenced by the fact that these emissions control strategies for non-EGUs are generally well demonstrated to be feasible on many existing units, as established through our review of consent decrees, permits, RACT determinations, and other data sources. These levels of emissions control have in many cases already been required by states with downwind nonattainment areas for the 2015 ozone NAAQS.

The EPA determined that, for 2026, the incremental average air quality improvement at receptors relative to the EGU case when SCR post-combustion controls were installed was 0.19 ppb when non-EGU controls were applied, based on the Step 3 analysis. The total average air quality improvement was 0.66 ppb when the non-EGU improvement was added to the EGU improvement, meaning that the non-EGU increment accounts for about 29 percent of this average air quality improvement. In general, the air quality results from non-EGU emissions reductions yield additional important downwind benefits to the air quality benefits of the EGU strategy. For example, the total ppb improvement summed over all of the receptors from EGUs was 7.04 ppb and the non-EGU increment adds another 2.82 ppb of improvement bringing the total to 9.87 (when accounting for rounding). Non-EGUs account for 29 percent of this total air quality improvement as well. Further, these figures should not be considered in isolation; EPA is not comparing EGU strategy effects and non-EGU effects to make a selection between two different approaches. Rather, both the selected EGU and non-EGU emissions reduction strategies at the cost-effectiveness values identified in section V.B and V.C of this document present a comprehensive solution to eliminating significant contribution for the covered states. The combined effect of the EGU and non-EGU strategies is further presented in the following section.

TABLE V.D.2–2—AIR QUALITY AT RECEPTORS IN 2026 FROM NON-EGU INDUSTRIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU
40278011	Arizona	Yuma	69.87	69.80	71.47	71.40
80590006	Colorado	Jefferson	71.70	71.34	72.30	71.93
80590011	Colorado	Jefferson	72.06	71.57	72.66	72.16
80690011	Colorado	Larimer	69.84	69.53	71.04	70.72
90013007	Connecticut	Fairfield	71.25	70.66	72.06	71.46
90019003	Connecticut	Fairfield	71.58	71.06	71.78	71.26
350130021	New Mexico	Dona Ana	70.06	69.86	71.36	71.16
350130022	New Mexico	Dona Ana	69.17	68.96	71.77	71.56
350151005	New Mexico	Eddy				
350250008	New Mexico	Lea				
480391004	Texas	Brazoria	69.89	68.50	72.02	70.58
481671034	Texas	Galveston	71.29	69.28	72.51	70.47
482010024	Texas	Harris	74.83	73.39	76.45	74.98
490110004	Utah	Davis	69.90	69.28	72.10	71.46
490353006	Utah	Salt Lake	70.50	69.91	72.10	71.50
490353013	Utah	Salt Lake	71.91	71.40	72.31	71.80
551170006	Wisconsin	Sheboygan	70.83	70.27	71.73	71.17
Average AQ Change Relative to Base (ppb)						0.66
Total PPB Change Across All Receptors Relative to Base (ppb)						9.87

Table Notes:

[a] The EPA notes that the design values reflected in Table V.D.–2 correspond to the engineering analysis EGU emissions inventory that was used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Final Rule TSD.

[b] New Mexico Eddy and Lea monitors have no values in Table V.D.2–2 as EPA does not have calibration factors for these monitors as no contributions were calculated for them from the proposal AQ modeling.

[c] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section VIII of this document provides a more complete picture of the air quality impacts of the final rule.

[250] Nonetheless, recognizing the diverse non-EGU industries and emissions units covered in this action and the potential that certain individual facilities and emissions units may face extreme hardship in meeting the general requirements being finalized in this action, the EPA has provided mechanisms in the regulatory requirements for industrial sources that provide for some flexibility in the emissions limits based on a demonstration of technical impossibility or extreme economic hardship. *See* section VI.C of this document.

For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Final Rule TSD and to the Ozone AQAT included in the docket for this rule.

3. Combined EGU and Non-EGU Assessment

The EPA used the Ozone AQAT to evaluate the combined impact of these selected stringency levels for both EGUs and non-EGUs on all receptors remaining in the 2026 air quality modeling base case to inform the air quality effects of the rule and to conduct our over-control analysis. EPA's evaluation demonstrated air quality improvement at the remaining nonattainment or maintenance receptors outside of California (*see* section IV.D of this document for receptor details). The EPA estimated that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.66 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, application of new post-combustion control (SCR and SNCR) retrofits at eligible units, and all estimated emissions reductions from the non-EGU industries. Table V.D.3–1 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT. In summary, the collective application of these mitigation measures and emissions reductions are projected to deliver meaningful downwind air quality improvements.

TABLE V.D.3–1—CHANGE IN AIR QUALITY AT RECEPTORS IN 2026 FROM FINAL RULE EGU AND NON-EGU EMISSIONS REDUCTIONS [a b c]

Sector/technology	Ozone season emissions reductions	Total PPB change across all downwind receptors [d]	Average PPB change across all downwind receptors
EGU (SCR/SNCR optimization + LNB upgrade)	16,282	0.71	0.05
EGU SCR/SNCR Retrofit	55,672	6.34	0.42
Non-EGU Industries	44,616	2.82	0.19
Total	....	9.87	0.66

Table Notes:

[a] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. In addition, this method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states and associated health and climate benefits are discussed in section VII of this document.

[b] The EPA notes that the design values reflected in Tables V.D.1–1 and –2 correspond to the engineering analysis EGU emissions inventory used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Final Rule TSD. Additionally, these emissions reduction values vary slightly from the technology reduction estimates described in section V.C of this document, as the values here reflect the sum of the final identified stringency for each state (*e.g.,* SCR retrofit potential is not assumed in Alabama, Minnesota, and Wisconsin).

[c] The total and average ppb results from non-EGUs emissions reductions shown here were generated using the Step 3 AQAT methodology consistent with that for EGUs (*i.e.,* including reductions from the state containing the receptor and excluding states that are not explicitly linked to particular receptors). The values shown in Table V.C.2–1 were prepared for the non-EGU screening assessment using a methodology where states within the program make emissions reductions for all receptors. States that contain receptors (*i.e.,* Connecticut and Colorado) that are not linked to other receptors are not assumed to make reductions under that methodology.

[d] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section VIII of this document provides a picture of the projected air quality impacts of the final rule using modeling techniques that differ from the methodologies employed here.

4. Over-Control Analysis

The EPA applied its over-control test to this same set of aggregated EGU and non-EGU data described in the previous section. The EPA performed air quality analysis using the Ozone AQAT to determine whether the emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario. As in prior transport rules following the holdings in *EME Homer City,* overcontrol would be established if the record indicated that, for any given state, there is an identified, less stringent emissions control approach for that state, by which (1) the expected ozone improvements would be sufficient to resolve all of the downwind receptor(s) to which that state is linked; or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb) to all receptors. In *EME Homer City,* the Supreme Court held that the EPA cannot ''require[] an upwind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked.'' 572 U.S. at 521. On remand from the Supreme Court, the D.C. Circuit held that this means that the EPA might overstep its authority ''when those downwind locations would achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations.'' *EME Homer City II,* 795 F.3d at 127. The D.C. Circuit qualified this statement by noting that this ''does not mean that every such upwind state would then be entitled to less stringent emissions limits. Some of those upwind States may still be subject to the more stringent emissions limits so as not to cause other downwind locations to which those States are linked to fall into nonattainment.'' *Id.* at 14–15. Further, as the Supreme Court explained, ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' 572 U.S. at 523. The Court noted that ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution'' and that incidental over-control may be unavoidable. *Id.* ''Required to balance the possibilities of under-control and over-control, EPA must have leeway in fulfilling its statutory mandate.'' *Id.*[251]

[251] Although the Court described over-control as going beyond what is needed to address ''nonattainment'' problems, the EPA interprets this

Consistent with these instructions from the Supreme Court and the D.C. Circuit, using the Ozone AQAT, the EPA first evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions selected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems (see the Ozone Transport Policy Analysis Final Rule TSD for details on the construction and application of AQAT).

Similar to our approach in the CSAPR Update and the Revised CSAPR Update, our primary overcontrol assessment examines the receptor changes from the emissions reductions of the upwind states found linked to a receptor. Consistent with prior Rules, EPA also assumed that downwind states that are not upwind states in this rule implement reductions commensurate with the rule's requirements (this treatment applies specifically to Colorado and Connecticut). This configuration effectively presents an equitable representation of the effects of the rule in that linked upwind states do not shift their responsibility to other upwind states linked to different receptors. It also effectively resolves any interdependence and ''which state goes first?'' questions. Furthermore, the downwind states in which a receptor is located are held to a ''fair share'' of emissions reductions—*i.e.,* the same level of emissions control stringency that the upwind states must implement.

The EPA also repeated this analysis using an alternative configuration, as described in the Ozone Transport Policy Analysis Final Rule TSD. In this configuration, we looked at the combined effect of the entire program across all linked upwind states on each receptor and did not assume that a downwind state that is not also an upwind state makes any additional emissions reductions beyond the baseline in the relevant year. This configuration effectively isolates how the rule as a whole, and just the rule, will affect air quality and linkages. While the first configuration described is, in the Agency's view, the more appropriate way to evaluate overcontrol, taken together the configurations provide a more robust basis on which to rest our conclusions regarding overcontrol. In any case, as further illustrated in the Ozone Transport Policy Analysis Final Rule TSD, our analysis under both configurations establishes that there is no overcontrol and so there is no need to reconcile any difference in results between them.

We also looked at the ordering of increments of emissions reduction and have found that it does not matter whether we assume EGU emissions controls would be applied first, followed by non-EGU controls, or vice-versa. For 2023, the question is moot as there are only EGU reductions to examine. For 2026, the analysis showed there would be no overcontrol either way. In 2026, the EPA's overcontrol analysis (as presented here) examined all EGU reductions first and layered in non-EGU reductions in the last step of the overcontrol check. However, the EPA also examined an alternative ordering scenario where the non-EGU reductions were assessed prior to the EGU reductions associated with installation of new SCR post-combustion controls (see the Ozone Transport Policy Analysis Final Rule TSD for details). This ordering did not impact the results of the overcontrol test. The specific results of these analyses are presented in the TSD.

The control stringency selected for 2023 (a representative cost threshold of $1,800 per ton for EGUs) includes emissions reductions commensurate with optimization of existing SCRs and SNCRs and installation of state-of-the-art combustion controls, is not estimated to change the status of any receptors.[252] Thus, the nonattainment or maintenance receptors that the states are linked to remain unresolved. Nor do any states' contribution levels drop below the 1 percent of NAAQS threshold. Thus, the EPA determined that none of the 23 linked states have all of their linkages resolved at the final EGU level of control stringency in 2023, and hence, the EPA finds no over-control in the final level of stringency.

Based on the air quality baseline modeling for 2026, all receptors to which Alabama, Minnesota, and Wisconsin are linked in 2023 are projected to be in attainment in 2026. Therefore, no additional stringency is finalized for EGUs or non-EGUs in those states beyond the 2023 level of stringency. For the remaining 20 states, the selected control stringency beginning in 2026 includes additional EGU controls and the non-EGU emissions reductions.

The EPA assesses air quality impacts and overcontrol in the year 2026 in this final rule, even though the rule accommodates the potential need for individual facilities (both EGU and non-EGU) to have some additional time to come into compliance. The EPA views this additional time to be a reflection of need (based on demonstrated impossibility) that is justified at Step 4 of the interstate transport framework rather than at Step 3. As explained in section VI.A of this document, with respect to EGUs, the EPA extends the full implementation of the SCR retrofit-based reductions across 2026 and 2027 to accommodate any *unit-level* scheduling challenges. However, we find that many sources can meet a three-year installation time and the trading program features and the allowance price will incentivize these reductions to occur as soon as possible. Similarly, with respect to non-EGU industrial sources, the final rule provides limited circumstances for individual facilities to seek and to be granted extensions of time to install required pollution controls and achieve the emissions rates established in this rule based on a showing of necessity. Those circumstances where an extension may be warranted for any specific facility are unknown at this time and will be evaluated through a source-specific application process, where the need for extension can be established with source-specific evidence. See section VI.C of this document. Further, 2026 is the critical analytic year associated with the last full ozone season before the 2027 Serious area attainment date and is the year by which significant contribution must be eliminated if at all possible. Therefore, for purposes of this analysis, the collective *state and regional* representation of these reductions are fully assumed in 2026. The potential ability of both EGU and non-EGU sources to have some amount of additional time beyond 2026 to comply with requirements that we have determined at Step 3 are necessary to eliminate significant contribution does not necessitate evaluating a later year than 2026 for overcontrol. The stringency of the control program does not alter in any year beyond 2026.[253] By

holding as not impacting its approach to defining and addressing both nonattainment and maintenance receptors. In particular, the EPA continues to interpret the Good Neighbor provision as requiring it to give independent effect to the ''interfere with maintenance'' prong. *Accord Wisconsin,* 938 F.3d at 325–27.

[252] For purposes of this rule, the violating monitor receptors inform our determinations at Step 1 and 2 by strengthening the analytical basis on which we conclude upwind states are linked in 2023. Because no linkages identified using our air quality modeling methodology resolve in 2023 under the selected control stringency, it is not necessary to evaluate overcontrol with respect to the additional set of violating-monitor receptors.

[253] Thus, we note, this circumstance is different than the record on which overcontrol was found in *EME Homer City.* There, CSAPR would have implemented an increase in the emissions control stringency of the rule (as reflected in a change in emissions control stringency expressed as dollars

Continued

fully reflecting all Step 3 emissions reductions in its overcontrol test for 2026, EPA ensures that it is not understating the emissions impact and benefit when performing the test.

The EPA used the Ozone AQAT to evaluate the impact of this selected stringency level (as well as other potential stringency levels) on all receptors remaining in the 2026 air quality modeling base case. This assessment shows that the selected control stringency level is estimated to change the status of three receptors to attainment or maintenance in 2026. Brazoria County, Texas (Monitor ID 480391004); and Galveston County, Texas (Monitor ID 481671034), are estimated to come into attainment. We observe that one of the Fairfield, Connecticut, receptors (Monitor ID 090013007) is estimated to go from nonattainment to maintenance (when EGU emissions reductions with SCR are applied, prior to the application of the non-EGU emissions reductions). This receptor is expected to remain in maintenance even after the application of the non-EGU emissions reductions. Based on these data, EPA finds that all linked states except Arkansas, Mississippi, and Oklahoma are projected to continue to be linked to nonattainment or maintenance receptors after implementation of all identified Step 3 reductions, and hence, the EPA finds no over-control in its determination of that level of stringency for those states. Arkansas, Mississippi, and Oklahoma are linked to at least one of the two Texas receptors that are projected to come into attainment with the full implementation of the control strategy at Step 3. However, these two Texas receptors are expected to remain as maintenance-only receptors prior to the final increment of reductions assessed (the addition of the non-EGU reductions), so EPA concludes that imposition of the incremental non-EGU level is appropriate to avoid under-control as to these states and does not constitute overcontrol.[254]

Next, the EPA evaluated the potential for over-control with respect to the 1 percent of the NAAQS threshold applied in this final rulemaking at Step 3 of the good neighbor framework, assessed for the selected control stringencies for each state for each period that downwind nonattainment and maintenance problems persist (*i.e.,* 2023 and 2026). Specifically, the EPA evaluated whether the selected control stringencies would reduce upwind emissions to a level where the contribution from any of the 23 linked states in 2023 or 20 linked states in 2026 would be below the 1 percent threshold. The EPA finds that for the mitigation measures assumed in 2023 and in 2026, all states that contributed greater than or equal to the 1 percent threshold in the base case are projected to continue to contribute greater than or equal to 1 percent of the NAAQS to at least one remaining downwind nonattainment or maintenance receptor for as long as that receptor remained in nonattainment or maintenance. EPA notes that in 2026, for Oklahoma, when the incremental level of stringency associated with the non-EGU control strategy is applied, Oklahoma's contribution to Galveston County Texas is expected to drop below the 1 percent threshold (at the same time that the receptor has its maintenance problems resolved). EPA concludes that this does not constitute overcontrol because both the receptor and the contribution are estimated to remain above the maintenance level and linkage threshold at the prior level of stringency and, thus, since otherwise justified at Step 3, the full stringency for 2026 is appropriate to avoid under-control. For more information about this assessment, refer to the Ozone Transport Policy Analysis Final Rule TSD and the Ozone AQAT.

Therefore, EPA finds that all of the selected EGU and non-EGU NO_X reduction strategies selected in EPA's Step 3 analysis can be applied to all states linked in 2026 to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone NAAQS without introducing an overcontrol problem based on the present record. The Supreme Court has directed the EPA to avoid both over-control and under-control in addressing good neighbor obligations. In addition, the D.C. Circuit has reinforced that over-control must be established based on particularized, record evidence on an as-applied basis.

The determination that the stringency of this action does not constitute overcontrol for any linked state is further reinforced by EPA's observation in section III.A of this document regarding the nature of the ozone problem. Ozone levels are known to vary, at times dramatically, from year to year. Future ozone concentrations and the formation of ground level ozone may also be impacted by factors in future years that the EPA cannot fully account for at present. For example, changes to meteorological conditions could affect future ozone levels. Climate change could also contribute to higher than anticipated ozone levels in future years through wildfires and heat waves, which can contribute directly and indirectly to higher levels of ozone. Any modeling projection can be characterized as having some uncertainty, and that is not a sufficient reason to ignore modeling results. However, in the context of the overcontrol test, the question is whether it is clear according to particularized evidence that there is no need for the emissions reductions in question. *See EME Homer City,* 572 U.S. at 523 (''[A] degree of imprecision is inevitable in tackling the problem of interstate air pollution. Slight changes in wind patterns or energy consumption, for example, may vary downwind air quality in ways EPA might not have anticipated.''). Under this standard, the degree of attainment that is projected to occur under the rule in relation to the Texas receptors discussed above is not so large or certain to occur that it would be appropriate to attempt to devise a less stringent emissions control strategy for the relevant linked states as a result, particularly in light of the fact that at the penultimate stringency level the receptors are not resolved.

It is also possible that ozone-precursor emissions from certain sources may decline beyond what we currently project in this rule. For example, the IRA may result in reductions in fossil-fuel fired generation, which should in turn result in lower NO_X emissions during the ozone season.[255] We have

per ton from $100/ton to $500/ton). That change in stringency marked a determination that EPA had made at Step 3 regarding the degree of emissions reduction that sources needed to achieve beginning in 2014. But in that year, the court found EPA's record to reveal that certain states would not need to go up to that higher level of stringency because air quality problems and/or linkages were already projected to be resolved at the lower level of stringency. *See* 795 F.3d at 128–30. The analogous year to 2014 here is 2026. The stringency level of this control program does not change post-2026. Nor do we think individual sources should gain the benefit of delaying emissions reductions simply in the hopes that they could show those reductions would be overcontrol; each source must be held to the elimination of its portion of significant contribution. Necessity may demand some additional amount of time for compliance, but equity demands that individual sources not gain an untoward advantage from delay and reliance on other sources' timelier compliance.

[254] Even with full implementation of the rule, these two receptors are only projected to come into attainment by a relatively small degree, and no policy option is ascertained in the record by which attainment could be achieved to an even lesser degree. Nonetheless, the EPA further evaluated whether there were any overcontrol concerns through sensitivity analyses. Under all scenarios, the EPA finds there is no overcontrol. See the Ozone Transport Policy Analysis Final Rule TSD for more discussion and analysis.

[255] As discussed in section IV.C.2.b, there are also potential ways in which the IRA may not necessarily result in reductions in NO_X emissions from EGUs.

assessed this scenario to ensure our overcontrol conclusions are robust even if the IRA has those effects. As discussed in the Regulatory Impact Analysis, the EPA conducted additional modeling of the final policy scenario (inclusive of economically efficient methods of compliance available within the Step 4 implementation programs) using its IPM tool. The EPA observes that the differences in estimated costs and emissions reductions in the IRA sensitivity (presented in Appendix 4A of the RIA) suggests that there would also be differences in estimated health and climate benefits under that scenario, although the Agency did not have time under this rulemaking schedule to quantify those differences. The EPA also used AQAT to conduct an additional EGU modeling sensitivity reflecting the IRA. Both the IPM sensitivity and the corresponding AQAT assessment of the IRA scenarios demonstrated no overcontrol as every state linkage to a downwind problematic receptor persisted in the penultimate level of stringency when EPA performed its Step 3 evaluation—even when the impacts of the IRA are incorporated. This further affirmed EPA's conclusion of no overcontrol concerns at the stringency level of the final rule. This overcontrol sensitivity is further discussed in the Ozone Transport Policy Analysis Final Rule TSD, Appendix K.

In light of the mandate of the CAA to protect the public health and environment through the elimination of significant contribution under the Good Neighbor Provision for the 2015 ozone NAAQS, nothing in the present record establishes on an as-applied, particularized basis that this rule will result in an unnecessary degree of control of upwind-state emissions.

Comment: Many commenters alleged that the rule overcontrols emissions by more than necessary to eliminate significant contribution for the 2015 ozone NAAQS, on the basis that the emissions reductions are unnecessary or are unnecessarily stringent.

Response: As discussed earlier in this section, EPA has analyzed whether this rule ''overcontrols'' emissions and has found based on a robust, multi-faceted analysis, that it does not. In particular, EPA has not identified a lesser-stringency emissions control strategy for any state that would either fully resolve the air quality problems at a downwind receptor location or resolve that upwind state's linkage to a level below the 1 percent of NAAQS contribution threshold. No commenter has provided a particularized, as-applied analysis demonstrating that EPA's emissions control strategy will actually result in any overcontrol of emissions in the manner the EPA or courts have understood that term, and overcontrol allegations must be proven through particularized, as-applied challenges. *See EME Homer City,* 795 F.3d at 127; *see also Wisconsin,* 938 F.3d at 325 (''[T]he way to contest instances of over-control is not through generalized claims that EPA's methodology would lead to over-control, but rather through a 'particularized, as-applied challenge.' '' Accordingly, as we did when presented with similar arguments in *EME Homer III,* we reject Industry Petitioners' arguments because they do no more than speculate that aspects of 'EPA's methodology *could* lead to over-control of upwind States.' '') (cleaned up) (citing *EME Homer City,* 795 F.3d at 136–137).

Comment: For 2 of the 20 states linked in 2026, Arkansas and Mississippi, the last downwind receptor to which these two states are linked (*i.e.,* Brazoria County, Texas) was estimated to achieve attainment and maintenance after full application of EGU reductions and Tier 1 non-EGU reductions at proposal. Commenters noted that this suggested application of the estimated non-EGU, and/or some EGU, emissions reductions constituted over-control for these states.

Response: EPA notes that at proposal, this downwind receptor only resolved by a small margin after the application of all EGU and Tier 1 non-EGU emissions reductions. As explained earlier in this section, the final rule air quality modeling shows that the receptors to which these states are linked do not resolve upon full implementation of the identified EGU reductions by themselves, and only reach attainment by a small degree following the additional reductions from the non-EGU control strategy.[256] If the EPA were to select the control stringency of this penultimate step, both upwind-state contribution and downwind-state air quality receptors would persist while the cost-effective emissions reductions that were identified to eliminate significant contribution remain available but un-implemented. This would constitute under-control. Consequently, as described, the EPA views the control stringency required of these states in this final rule as not constituting over-control and appropriate to eliminate significant contribution to nonattainment and interference with maintenance of this NAAQS in line with our Step 3 determinations for all other states. See the Ozone Transport Policy Analysis Final Rule TSD section C.3 for discussion and analysis regarding overcontrol for states solely linked to one or both of these receptors.

Comment: Commenters raised a variety of arguments that the enhancements to the EGU trading program in this action will result in overcontrol of power plant emissions. They alleged that dynamic budgeting would cause the budget to continually decrease even after significant contribution is eliminated. They similarly argue that annual emissions bank recalibration and the emissions backstop emissions rate have not been shown to be justified to eliminate significant contribution.

Response: This final rule's determination regarding the appropriate level of control stringency for EGUs finds that the amounts of NO_X emissions reduction achieved through these strategies at EGUs are appropriate and cost-justified under the Step 3 multifactor analysis. These determinations are associated with particular emissions control technologies and strategies as detailed in sections V.B.1 and V.C.1 above. It is the implementation of those strategies at the covered EGU sources and the air quality effects of those strategies (coupled with non-EGUs) in the relevant analytic year of 2026 on which we base our determination of significant contribution at Step 3. This includes the evaluation of whether there is overcontrol, which is also conducted for the 2026 analytic year as explained above. As explained below, we disagree that the enhancements to the trading program at Step 4 implicate the need for further overcontrol analysis. These enhancements operate together to ensure the trading program continues to maintain the Step 3 emissions control stringency over time. These enhancements reflect lessons learned through EPA's experience with prior trading programs implemented under the good neighbor provision. None of commenters' arguments that these enhancements result in overcontrol are persuasive.

Commenters contend that these enhancements to the trading program go

[256] Because in the final record we do not identify cost, air quality, and emission reduction factors that sufficiently differentiate either source-type or emissions control strategy among the Tier 1 and Tier 2 industries identified at proposal, we combined the non-EGU industries and emissions reductions into one group, and we are finalizing requirements for all non-EGU industries and most emissions unit types identified at proposal. In light of the small degree to which the relevant receptors reach attainment and the multi-faceted assessment of overcontrol we have undertaken, the overcontrol assessment with respect to non-EGUs in the final rule is sufficient to establish that there is no overcontrol.

beyond a mass-based budget approach as applied in CSAPR. Because these improvements in the program result in a continuing incentive for each covered EGU source to maintain the pollution control performance the EPA found appropriate to eliminate significant contribution at Step 3, commenters believe these enhancements must necessarily result in prohibited overcontrol. These arguments appear to be premised on the assumption that overall emissions may later decline to such a point that there is no longer a linkage between a particular state and any downwind receptors for reasons other than the requirements of this rule.

As an initial matter, no commenter has provided an empirical analysis demonstrating that the control stringency identified at Step 3 to eliminate significant contribution would actually result in any overcontrol. The case law is clear that over-control allegations must be proven through particularized, as-applied challenges. See prior response to comments. More importantly here, the Group 3 trading program enhancements do not impose increased stringency in years after 2030 and do not force emissions to continually be reduced to ever lower levels. They are only designed to incentivize the implementation of the Step 3 emissions control stringency that eliminates significant contribution. The circumstances that could potentially cause a receptor or linkage to resolve at some point in the future after 2026 are not circumstances that are within the power of this rule to control. Nor would those circumstances present a justification as to why upwind sources should no longer be obligated to eliminate their own significant contribution. *Wisconsin,* 938 F.3d at 324–25 (rejecting overcontrol arguments premised on attributing air quality problems to other emissions).

Further, the EPA is not constrained by the statute to only implement good neighbor obligations through fixed, unchanging, mass-based emissions budgets. *See* section III.B.1 of this document. The EPA has defined the ''amount'' of emissions that must be prohibited to eliminate significant contribution in this action based on a series of determinations of which emissions control strategies, for certain identified EGU and non-EGU sources, are appropriate applying the Step 3 multifactor analysis. Notably, the non-EGU industrial source emissions reductions in this action are *not* being achieved at Step 4 through mass-based emissions trading, nor are they required to be by any provision of the CAA. See section III.B.1.

As explained in sections III.B.1.d and VI.B.1 of this document, the EPA finds good reason based on its experience with trading programs that using fixed, mass-based, ozone-season wide budgets does not necessarily ensure the elimination of significant contribution over the entire region of linked states or throughout each ozone season. Even in the original CSAPR rulemaking, which promulgated only fixed, mass-based budgets, such outcomes were never the EPA's intention to allow. *See, e.g.,* 76 FR 48256–57 (''[I]t would be inappropriate for a state linked to downwind nonattainment or maintenance areas to stop operating existing pollution control equipment (which would increase their emissions and contribution).''). Despite the EPA's expectations in CSAPR, the experience of the Agency since that time establishes a real risk of ''under-control'' if the existing trading framework is not enhanced. *See EME Homer City,* 572 U.S. at 523 (''[T]he Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'').

Further, the EPA has already once adjusted its historical approach to better account for known, upcoming changes in the EGU fleet to ensure mass-based emissions budgets adequately incentivize the control strategy determined at Step 3. This adjustment was introduced in the Revised CSAPR Update. *See* 82 FR 23121–22. The EPA now believes it is appropriate to ensure in a more comprehensive manner, and in perpetuity, that a mass-based emissions-trading framework incentivizes continuing implementation of the Step 3 control strategies to ensure significant contribution is eliminated in all upwind states and remains so. This is fully analogous in material respect to an approach to implementation at Step 4 that relies on application of unit-specific emissions limitations, which under the Act would typically apply in perpetuity and may only be modified through a future SIP- or FIP-revision rulemaking process. *See* CAA section 110(i) prohibiting modifications to implementation plan requirements except by enumerated processes. The availability of unit-specific emissions rates as a means to eliminate significant contribution is discussed in further detail in section III.B.1 of this document. The EPA also explained this in the proposal. *See* 87 FR 20095–96.

Further, these enhancements are directly related to assisting downwind areas specifically with the goal of attaining and maintaining the 2015 8-hour ozone NAAQS. In this respect, they are not ''unnecessary'' or ''unrelated'' to carrying out the mandates of CAA section 110(a)(2)(D)(i)(I). Taking measures to ensure that each upwind source covered by an emissions trading program is adequately incentivized to eliminate excessive emissions (as found at Step 3) throughout the entirety of each ozone season is entirely appropriate in light of the nature of the ozone problem. Ozone exceedances recur on varying days throughout the summertime ozone season, and it is not possible to predict in advance which specific days will have high ozone. Further, impacts to public health and the environment from ozone can occur through short-term exposure (*e.g.,* over a course of hours, *i.e.,* on a daily basis). The 2015 ozone NAAQS is expressed as an 8-hour average, and only a small number of days in excess of the ozone NAAQS can cause a downwind area to be in nonattainment. Thus, even a small number of exceedances can result in continuing and/or increased regulatory burdens on the downwind jurisdiction. Taking these considerations into account, it is evident that a fixed, mass-based emissions program that does not adequately incentivize emissions reductions commensurate with our Step 3 determinations on each day of every ozone season going forward does not provide a sufficient guarantee that the emissions that significantly contribute on those particular days and at particular receptor locations when ozone levels are at risk of exceeding the NAAQS have been eliminated. *See* section V.B.1.a and VI.B of this document for more discussion of data observations regarding SCR optimization.

These enhancements are also consistent with the general policies and principles EPA has long applied in implementing the NAAQS through the SIP/FIP framework of section 110. Emissions control measures relied on to meet CAA requirements must be permanent and enforceable and included in the implementation plan itself. *See, e.g., Montana Sulfur & Chem. Co.* v. *EPA,* 666 F.3d 1174, 1196 (9th Cir. 2012); 40 CFR 51.112(a). In the General Preamble laying out EPA's plans for implementing the 1990 CAA Amendments, the EPA identified a core ''principle'' that control strategies should be ''accountable.'' ''This means, for example, that source-specific limits should be permanent and must reflect the assumptions used in the SIP demonstrations.'' 57 FR 13498, 13568 (April 16, 1992). EPA went on, ''The principles of quantification, enforceability, replicability, and accountability apply to all SIPs and control strategies, including those involving emissions trading, marketable permits and allowances.'' *Id.* EPA also explained that its ''emissions trading policy provides that only trades producing reductions that are surplus, enforceable, permanent, and quantifiable can get credit and be banked or used in an emissions trade.'' *Id.* These principles follow from the language of the Act, including CAA section 110(a)(2), 107(d)(3)(E)(iii), 110(i), and 110(l). These provisions and principles further underscore the importance of ensuring that the emissions reductions the EPA has found necessary to eliminate significant contribution are in fact implemented on a consistent and permanent basis even within the context of an emissions trading program.

The EPA disagrees that the budget adjustments that would occur over time under this final rule (for example, the annual dynamic-budget adjustment) must be reassessed each time they occur through notice and comment rulemaking under CAA section 307(d). This would serve no purpose. The formulas that the EPA will apply to adjust the budgets and allowance bank are set in this final rule and are intended to maintain, not increase (or decrease), program stringency. While the EPA intends to provide an opportunity for stakeholders to review and propose corrections to its data as it implements the established budget formulas, no larger reassessment of the emissions control program is needed on an ongoing basis, because, again, that program is simply calibrated to ensure that emissions reductions commensurate with the determination of ''significance'' in Step 3 continue to be obtained over the long term. As described earlier, these trading program provisions are analogous to, or mimic, the effect of unit-specific emissions limitations that apply in perpetuity.[257]

Commenters also confuse the ''amount'' of emissions that must be eliminated under CAA section 110(a)(2)(D)(i)(I) as being synonymous with a fixed, mass-based budget that reflects the residual emissions allowed following the elimination of significant contribution. However, EPA views the ''amount'' to be eliminated as those emissions that are in excess of the cost-effective emissions control strategies identified in Step 3. This is further explained in section III.B.1 of this document.

Thus, this rule is in compliance with the overcontrol principles that the D.C. Circuit applied on remand in *EME Homer City* to find certain instances of overcontrol in CSAPR's emissions control strategies. The D.C. Circuit found that EPA had imposed more stringent emissions-control strategies for certain states than were necessary to resolve all of those states' linkages. 795 F.3d at 128–30. Specifically, for sulfur dioxide, the court found certain receptors would reach attainment if all linked upwind states had implemented ''cost controls'' at $100/ton or $400/ton, rather than EPA's selected stringency level of $500/ton. Similarly, for ozone season NO_X, the court found that receptors were projected to attain the NAAQS at stringencies below $500/ton. The court's focus was on the *stringency* of the emissions control obligations as determined through the application of cost thresholds at Step 3 of the analysis. The court did not hold that EPA may only use fixed, mass-based budgets to implement those reductions. The court did not hold that EPA must permit individual polluting sources to be allowed to increase their emissions at some point in the future. The court did not hold that EPA's good neighbor FIPs must, effectively, contain termination clauses, such that they cease to ensure the implementation of the control stringency determined as necessary at Step 3, the moment a downwind receptor reaches attainment. Indeed, such a rule would contravene the statute's clear, forward-looking directive that EPA must also eliminate upwind emissions that interfere with *maintenance* of the NAAQS; *see North Carolina,* 531 F.3d at 908–911; *Wisconsin,* 938 F.3d at 325–26.

The *EME Homer City* court on remand in fact rejected various arguments that other aspects of EPA's emissions control strategy in CSAPR resulted in overcontrol, holding that EPA had properly given effect to the interfere with maintenance prong, and noting that petitioners failed to make out proven, as-applied demonstrations of overcontrol:

> At bottom, each of those claims is an argument that EPA's methodology could lead to over-control of upwind States that are found to interfere with maintenance at a downwind location. That could prove to be correct in certain locations. But the Supreme Court made clear in *EME Homer* that the way to contest instances of over-control is not through generalized claims that EPA's methodology would lead to over-control, but rather through a ''particularized, as-applied challenge.'' *EME Homer,* 134 S. Ct. at 1609, slip op. at 31. And petitioners do not point to any actual such instances of over-control at downwind locations.

795 F.3d at 137. The court went on to observe, ''EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.' If States have been forced to reduce emissions beyond that point, affected parties will have meritorious as-applied challenges.'' *Id.* (quoting 572 U.S. at 521–22). But this too was not a holding that EPA may not ensure effective and permanent implementation of an emissions control stringency that EPA has found warranted under CAA section 110(a)(2)(D)(i)(I). Such an approach is available through the more conventional CAA practice of setting unit-specific emissions limitations that would apply on a permanent and enforceable basis. *See* CAA sections 110(a)(2) and 302(y) (providing for SIPs and FIPs to include ''enforceable emissions limitations'' in addition to economic incentive measures like trading programs).[258] This is in fact how EPA intends to ensure significant contribution is eliminated from non-EGU industrial sources for which a mass-based trading regime is, at least at the present time, unworkable (see section VI.C of this document). And EPA has provided for the elimination of significant contribution through source-specific emissions limitations in prior transport actions as well, so this position is not novel. See section III.B of this document.

Nonetheless, EPA recognizes that under the Act, both FIPs and SIPs may be revised, and states may replace FIPs with SIPs if EPA approves them. Any such revision must be evaluated to ensure no applicable CAA requirements are interfered with. *See, e.g., Indiana* v. *EPA,* 796 F.3d 803 (7th Cir. 2015). For example, states may be able to demonstrate in the future that through some other permanent and enforceable methods of emissions reduction that they have adopted into their SIP, they will be able to achieve a similar emissions control stringency with different emissions reduction requirements imposed on different sources as compared to the FIPs finalized in this action. See section VI.D of this document.

Therefore, commenters' contentions that EPA's trading program enhancements result in prohibited

[257] We note further that because all of the trading program provisions, including the dynamic budget-setting provisions and process, are established by this final FIP rulemaking, the ministerial future-year budget adjustment process complies with the CAA section 110(i) prohibition on modification of implementation plan requirements except by enumerated process.

[258] ''Emissions limitation'' is in turn defined at CAA section 302(k) as a ''requirement . . . which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis. . . .''

overcontrol are not proven through as-applied, particularized challenges, and they are premised on an incorrect understanding of the CAA and the relevant case law. The Agency rejects the contention that it must somehow provide in the present FIP action for a relaxation in the stringency of the Step 4 implementation program and thus allow for the recurrence of pollution that we have found here, in this action, significantly contributes to downwind ozone nonattainment and maintenance problems.

VI. Implementation of Emissions Reductions

A. NO_X Reduction Implementation Schedule

This action will ensure that emissions reductions necessary to eliminate significant contribution will be achieved ''as expeditiously as practicable'' and no later than the downwind attainment dates except where compliance by those dates is not possible. *See* CAA section 181(a); *Wisconsin,* 938 F.3d at 318–20. The timing of this action will provide for all possible emissions reductions to go into effect beginning in the 2023 ozone season for the covered states, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date will take effect as expeditiously as practicable. Emissions reductions commensurate with SCR mitigation measures for EGUs will start in 2026 and be fully implemented by 2027. Emissions reductions through the mitigation measures for industrial sources will generally go into effect in 2026; however, as explained in section VI.C of this document, we have provided for case-by-case extensions of up to one year based on a demonstration of necessity (with the potential for up to an additional two years based on a further demonstration). The full suite of emissions reductions is generally anticipated to take effect by the 2027 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. This rule constitutes a full remedy for interstate transport for the 2015 ozone NAAQS for the states covered; the EPA does not anticipate further rulemaking to address good neighbor obligations under this NAAQS will be required for these states with the finalization of this rule.

EPA's determinations regarding the timing of this rule are informed by and in compliance with several recent court decisions. The D.C. Circuit has reiterated several times that, under the terms of the Good Neighbor Provision, upwind states must eliminate their significant contributions to downwind areas ''consistent with the provisions of [title I of the Act],'' including those provisions setting attainment deadlines for downwind areas.[259] In *North Carolina,* the D.C. Circuit found the 2015 compliance deadline that the EPA had established in CAIR unlawful in light of the downwind nonattainment areas' 2010 deadline for attaining the 1997 NAAQS for ozone and $PM_{2.5}$.[260] Similarly, in *Wisconsin,* the Court found the CSAPR Update unlawful to the extent it allowed upwind states to continue their significant contributions to downwind air quality problems beyond the downwind states' statutory deadlines for attaining the 2008 ozone NAAQS.[261] In *Maryland,* the Court found the EPA's selection of a 2023 analysis year in evaluating state petitions submitted under CAA section 126 unlawful in light of the downwind Marginal nonattainment areas' 2021 deadline for attaining the 2015 ozone NAAQS.[262] The Court noted in *Wisconsin* that the statutory command—that compliance with the Good Neighbor Provision must be achieved in a manner ''consistent with'' title I of the CAA—may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, ''under particular circumstances and upon a sufficient showing of necessity,'' but concluded that ''[a]ny such deviation would need to be rooted in Title I's framework'' and would need to ''provide a sufficient level of protection to downwind States.'' [263]

1. 2023–2025: EGU NO_X Reductions Beginning in 2023

The near-term EGU control stringencies and corresponding reductions in this rulemaking cover the 2023, 2024, and 2025 ozone seasons. This is the period in which some reductions will be available, but the portion of full remedy reductions related to post combustion control installation identified in sections V.B through V.D of this document are not yet available. The EGU NO_X mitigation strategies available during these initial 3 years are the optimization of existing post-combustion controls (SCRs and SNCRs) and combustion control upgrades. As described in sections V.B through V.D of this document and in accompanying TSDs, these mitigation measures can be implemented in under two months in the case of existing control optimization and in 6 months in the case of combustion control upgrades. These timing assumptions account for planning, procurement, and any physical or structural modification necessary. The EPA provides significant historical data, including the implementation of the most recent Revised CSAPR Update, as well as engineering studies and input factor analysis documenting the feasibility of these timing assumptions. However, these timing assumptions are representative of fleet averages, and the EPA has noted that some units will likely overperform their installation timing assumptions, while others may have unit configuration or operational considerations that result in their underperforming these timing assumptions. As in prior interstate transport rules, the EPA is implementing these EGU reductions through a trading program approach. The trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions.

However, starting in 2024, as described in section VI.B.7 of this document, unit-specific backstop daily emissions rates are applied to coal units with existing SCR at a level consistent with operating that control. The EPA believes that implementing these emissions reductions through state emissions budgets starting in 2023 while imposing the unit-specific backstop emissions rates in 2024 achieves the necessary environmental

[259] *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), and *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020).

[260] *North Carolina,* 531 F.3d at 911–913.

[261] *Wisconsin,* 938 F. 3d at 303, 3018–20.

[262] *Maryland,* 958 F.3d at 1203–1204. Similarly, in *New York* v. *EPA,* 964 F.3d 1214 (D.C. Cir. 2020), the Court found the EPA's selection of a 2023 analysis year in evaluating New York's section 126 petition unlawful in light of the New York Metropolitan Area's 2021 Serious area deadline for attaining the 2008 ozone NAAQS. 964 F.3d at 1226 (citing *Wisconsin* and *Maryland*).

[263] *Wisconsin,* 938 F. 3d at 320 (citing CAA section 181(a) (allowing one-year extension of attainment deadlines in particular circumstances) and *North Carolina,* 531 F.3d at 912).

performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding daily operation of optimized SCRs.

Additionally, as in prior rules, the EPA assumes combustion control upgrade implementation may take up to 6 months. In the Revised CSAPR Update, covering 12 of the 22 states for which emissions reduction requirements for EGUs are established under this action, the EPA finalized the rule in March of 2021 and thus did not require these combustion control-based emissions reductions in ozone-season state emissions budgets until 2022 (year two of that program).[264] The EPA is applying the same timing assumption regarding combustion control upgrades for this rulemaking. Given the same relationship here between the date of final action and the year one ozone season, the EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until year two (*i.e.,* the 2024 ozone season). Any identified combustion control upgrade emissions reductions are reflected beginning in the 2024 ozone-season budgets for all covered states. For the 12 states covered under the Revised CSAPR Update, any identified emissions reduction potential from combustion control upgrade is included and reflected in those state budgets beginning in 2024—which means EGUs in those states have even more time than the 14 months between finalization of this rule and the 2024 ozone season if they started any planning or installation earlier in response to the Revised CSAPR Update.

2. 2026 and Later Years: EGU and Stationary Industrial Source NO_X Reductions Beginning in 2026

The EPA finds that it is not possible to implement all necessary emissions controls across all of the affected EGU and non-EGU sources by the August 3, 2024, Moderate area attainment date. In accordance with the good neighbor provision and the downwind attainment schedule under CAA section 181 for the 2015 ozone NAAQS, the EPA is aligning its analysis and implementation of the emissions reductions addressing significant contribution from EGU and non-EGU sources that require relatively longer lead time at a sectoral scale with the 2026 ozone season. The 2026 ozone season is the last full ozone season that precedes the August 3, 2027, Serious area attainment date for the 2015 ozone NAAQS.[265] The EPA proposed to require compliance with all of the remaining EGU and non-EGU control requirements beginning in the 2026 ozone season. The EPA continues to find 2026 to be the relevant analytic year for purposes of its Step 3 analysis, including its analysis of overcontrol, as discussed in section V.D.4 of this document. However, many commenters argued that full implementation of the EGU and industrial source control strategies is not feasible for every source by the 2026 ozone season. The EPA addresses these technical comments specifically in sections V.B and VI.C of this document. The EPA also commissioned a study to develop a better understanding of the time needed for installation of emissions controls for the industrial sector units covered in this rule, which is included in the docket and discussed in section VI.A.2.b of this document. While the EPA does not agree with all of the commenters' assertions regarding the time they claim is needed for control installation, in other respects the concerns raised were sufficient to justify some adjustments to the compliance schedule for the final rule. We have provided for the emissions reductions commensurate with assumed EGU post-combustion emissions control retrofits to be phased in over the 2026 and 2027 ozone season emissions budgets, and we have provided a process in the final regulations for individual non-EGU industrial sources to seek limited compliance extensions extending no later than 2029 based on a case-by-case demonstration of necessity. This compliance schedule delivers substantial emissions reductions in the 2026 and 2027 ozone seasons and before the 2027 Serious area attainment date, and it only allows compliance extensions beyond that attainment date based on a rigorous, source-specific demonstration of need for the additional time.[266]

The timing of this final rule provides three to four years for EGU and non-EGU sources to install whatever controls they deem suitable to comply with required emissions reductions by the start of the 2026 and 2027 ozone seasons. In addition, the publication of the proposal provided roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning (steps that can be taken prior to any capital investment) to be prepared to meet this implementation timetable.

The EPA views this timeframe for retrofitting post-combustion NO_X emissions controls and other non-EGU controls to be reasonable and achievable. A 3-year period for installation of control technologies is consistent with the statutory timeframe for implementation of the controls required to address interstate pollution under section 110(a)(2)(D) and 126 of the Act, the statutory timeframes for implementation of RACT in ozone nonattainment areas classified as Moderate or above, and other statutory provisions that establish control requirements for existing stationary sources of pollution.

For example, section 126 of the CAA authorizes a downwind state or tribe to petition the EPA for a finding that emissions from ''any major source or group of stationary sources'' in an upwind state contribute significantly to nonattainment in, or interfere with maintenance by, the downwind state. If the EPA makes a finding that a major source or a group of stationary sources emits or would emit pollutants in violation of the relevant prohibition in CAA section 110(a)(2)(D), the source(s) must shut down within three months from the finding unless the EPA directly regulates the source(s) by establishing emissions limitations and a compliance schedule extending no later than three years from the date of the finding, to eliminate the prohibited interstate transport of pollutants as expeditiously as practicable.[267] Thus, in the provision that allows for direct Federal regulation of sources violating the good neighbor provision, Congress established three years as the maximum amount of time available from a final rule to when emissions reductions need to be achieved at the relevant source or group of sources. Because this action is not taken under CAA section 126(c), the mandatory timeframe for implementation of emissions controls

[264] 86 FR 23093.

[265] For each nonattainment area classified under CAA section 181(a) for the 2015 ozone NAAQS, the attainment date is ''as expeditiously as practicable'' but not later than the date provided in table 1 to 40 CFR 51.1303(a). Thus, for areas initially designated nonattainment effective August 3, 2018 (83 FR 25776), the latest permissible attainment dates are: August 3, 2021 (for Marginal areas), August 3, 2024 (for Moderate areas), August 3, 2027 (for Serious areas), and August 3, 2033 (for Severe areas).

[266] While we generally use the term ''necessity'' to describe the showing that non-EGU facilities must meet in seeking compliance extensions, the elements for this showing are designed to allow the EPA to make a judgment that comports with the standard of ''impossibility'' established in case law such as *Wisconsin.* In other words, the ''necessity'' for additional time is effectively a showing by the source that it would be ''impossible'' for it to meet the compliance deadline.

[267] CAA 110(a)(2)(D)(i) and 126(c).

under that provision is not directly applicable, but it is informative.

In response to arguments from sources that more time than has been provided in the final rule is necessary, this provision strongly indicates that allowing time beyond a three-year period must be based on a substantial showing of impossibility. Our analysis based on comments and considering additional information is that the additional time we have provided in the final rule is both justified and sufficient in light of the statutory objective of expeditious compliance.

Additionally, for ozone nonattainment areas classified as Moderate or higher, the CAA requires states to implement RACT requirements less than three years after the statutory deadline for submitting these measures to the EPA.[268] Specifically, for these areas, CAA sections 182(b)(2) and 182(f) require that states implement RACT for existing VOC and NO_X sources as expeditiously as practicable but no later than May 31, 1995, approximately 30 months after the November 15, 1992, deadline for submitting RACT SIP revisions. For purposes of the 2015 ozone NAAQS, the EPA has interpreted these provisions to require implementation of RACT SIP revisions as expeditiously as practicable but no later than January 1 of the fifth year after the effective date of designation, which is less than three years after the deadline for submitting RACT SIP revisions.[269] For areas initially designated nonattainment with a Moderate or higher classification effective August 3, 2018 (83 FR 25776), that implementation deadline falls on January 1, 2023, approximately 29 months after the August 3, 2020 submission deadline.[270] Moderate ozone nonattainment areas must also implement all reasonably available control measures (including RACT) needed for expeditious attainment within three years after the statutory deadline for states to submit these measures to the EPA as part of a Moderate area attainment demonstration.[271] Nonattainment areas for the 2015 ozone NAAQS that were reclassified to Moderate nonattainment in October 2022 face this same regulatory schedule, meaning that their sources are required to implement RACT controls in 2023. With the exception of the Uinta Basin, which is not an identified receptor in this action, no Marginal nonattainment area met the conditions of CAA section 181(a)(5) to obtain a one-year extension of the Moderate area attainment date. 87 FR 60899 (Oct. 7, 2022). Thus, all Marginal areas (other than Uinta) that failed to attain have been reclassified to Moderate. *Id.* In the October 2022 final rulemaking EPA made determinations that certain Marginal areas failed to attain by the attainment date, reclassified those areas to Moderate, and established SIP submission deadlines and RACM and RACT implementation deadlines. EPA set the attainment SIP submission deadlines for the bumped up Moderate areas to be January 1, 2023. *See* 87 FR 60897, 60900. The implementation deadline for RACM and RACT is also January 1, 2023. *Id.*

The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA includes in this rule, as well as the types of emissions control technologies on which the EPA bases the emissions limitations that would take effect for the 2026 and 2027 ozone seasons, generally are consistent with the scope and stringency of RACT requirements for existing major sources of NO_X in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.[272] Thus, the timing Congress allotted for sources in downwind states to come into compliance with RACT requirements bears directly on the amount of time that should be allotted here and indicates, as does CAA section 126, that three years is an outer limit on the time that should be given sources to come into compliance where possible. In light of the January 1, 2023, deadline for implementation of RACT in Moderate nonattainment areas, the EPA finds that a May 1, 2026 deadline for full implementation of the emissions control requirements in this final rule would generally provide adequate time for any individual source to install the necessary controls, barring the circumstances of necessity discussed further in this section.

Finally, with respect to emissions standards for hazardous air pollutants, section 112(i)(3) of the CAA requires the EPA to establish compliance dates for each category or subcategory of existing sources subject to an emissions standard that ''provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard,'' with limited exceptions. CAA section 112(i)(3)(B) authorizes the EPA to grant an extension of up to 1 additional year for an existing source to comply with emissions standards ''if such additional period is necessary for the installation of controls,'' and sections 112(i)(4) through (7) provide for limited compliance extensions where other conditions are met.[273] Here again, where Congress was concerned with addressing emissions of pollutants that impact public health, a 3-year time period was allotted as the time needed for existing sources to come into compliance where possible. As discussed further in section VI.A.2.b of this document, the process for obtaining a compliance extension for industrial sources in this rule is generally modeled on 40 CFR 63.6(i)(3), which implements

[268] *See, e.g.,* 40 CFR 51.1112(a)(3) and 51.1312(a)(3)(i) (requiring implementation of RACT required pursuant to initial nonattainment area designations no later than January 1 of the fifth year after the effective date of designation, which is less than 3 years after the SIP submission deadline under 40 CFR 51.1112(a)(2)) and 51.1312(a)(2)(i), respectively).

[269] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation) and 40 CFR 51.1312(a)(3)(i) (requiring implementation of RACT SIP revisions as expeditiously as practicable, but no later than January 1 of the fifth year after the effective date of designation). For reclassified areas, states must implement RACT SIP revisions as expeditiously as practicable, but no later than the start of the attainment year ozone season associated with the area's new attainment deadline, or January 1 of the third year after the associated SIP revision submittal deadline, whichever is earlier; or the deadline established by the Administrator in the final action issuing the area reclassification. 40 CFR 51.1312(a)(3)(ii); *see* also 83 FR 62989, 63012–63014.

[270] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

[271] *See, e.g.,* 40 CFR 51.1108(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than 3 years after the deadline for submission of reasonably available control measures under 40 CFR 51.1112(c) and 51.1108(a)) and 40 CFR 51.1308(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than three years after the deadline for submission of reasonably available control measures under 40 CFR 51.1312(c) and 51.1308(a)). Because the attainment demonstration for a Moderate nonattainment area (including RACT needed for expeditious attainment) is due three years after the effective date of the area's designation (40 CFR 51.1308(a) and 51.1312(c)), and all Moderate nonattainment areas must attain the NAAQS as expeditiously as practicable but no later than 6 years after the effective date of the area's designation (40 CFR 51.1303(a)), the beginning of the ''attainment year ozone season'' (as defined in 40 CFR 51.1300(g)) for such an area is less than three years after the due date for the attainment demonstration.

[272] *See* the Final Non-EGU Sectors TSD for a discussion of SIP-approved RACT rules in effect in downwind states.

[273] *See, e.g.,* CAA section 112(i)(4), which provides for limited compliance extensions granted by the President based on national security interests.

the extension provision for existing sources under CAA section 112(i)(3)(B).

All of these statutory timeframes for implementation of new control requirements on existing stationary sources indicate that Congress considered 3 years to be not only a sufficient amount of time but an upper bound of time allowable (barring instances of impossibility) for existing stationary sources to install or begin the installation of pollution controls as necessary for expeditious attainment, to eliminate prohibited interstate transport of pollutants, and to protect public health.

Further, the EPA notes that, given the number of years that have passed since EPA's promulgation of the 2015 ozone NAAQS and related nonattainment area designations in 2018, and in light of the *Maryland* court's holding that good neighbor obligations for the 2015 ozone NAAQS should have been implemented by the Marginal area attainment date in 2021,[274] the implementation of good neighbor obligations for these NAAQS is already delayed, and the sources subject to NO_X emissions control in this rule have continued to operate for several years without the controls necessary to eliminate their significant contribution to ongoing and persistent ozone nonattainment and maintenance problems in other states. Under these circumstances, we find it reasonable to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in section V.B.1.b of this document beginning in the 2026 ozone season (with full implementation by the 2027 ozone season for EGUs, and the availability of source-specific extensions based on a demonstration of necessity for non-EGUs).

As the D.C. Circuit noted in *Wisconsin,* the good neighbor provision requires upwind states to ''eliminate their substantial contributions to downwind nonattainment in concert with the attainment deadlines'' in the downwind states, even where those attainment deadlines occur before EPA's statutory deadline under CAA section 110(c) to promulgate a FIP.[275] Referencing the Supreme Court's description of the attainment deadlines as ''the heart'' of the CAA, the *Wisconsin* court noted that some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity.''[276]

For the reasons provided in the following sub-sections, the EPA finds that installation of certain EGU controls and all non-EGU controls is not possible by the Moderate area attainment date for the 2015 ozone NAAQS (*i.e.,* August 3, 2024),[277] and, for certain sources, may not be possible by the 2026 ozone season or even the August 3, 2027, Serious area attainment date. While the EPA's technical analysis demonstrates that for any individual source, control installation could be accomplished by the start of the 2026 ozone season, in light of the scope of this rule coupled with current information on the present economic capacity of sources, control-installation vendors, and associated markets for labor and material, it is the EPA's judgment that a three-year timeframe is not possible for all sources subject to this rule collectively to come into compliance. Therefore, additional time beyond 2026 will be allowed for certain facilities in recognition of these constraints on the processes needed for installation of controls across all of the covered sources.

a. EGU Schedule for 2026 and Later Years

As discussed in sections V.B through V.D of this document, significant emissions reduction potential exists and is included in EPA's quantification of significant contribution based on the potential to install post-combustion controls (SCR and SNCRs) at EGUs. However, as discussed in detail in those sections, the assumption for installation of this technology on a region-wide scale is 36–48 months in this final rule. This amount of time allows for all necessary procurement, permitting, and installation milestones across multiple units in the covered region. Therefore, the EPA finds that these emissions reductions are not available any earlier than the 2026 compliance period. Starting in 2026, state emissions budgets will reflect full implementation of assumed SNCR mitigation measures and implementation of half the emissions reduction potential identified for assumed SCR mitigation measures. For each year in 2027 and beyond, state emissions budgets include all of the emissions reductions commensurate with these post-combustion control technologies identified for covered units in Step 3. The EPA notes that similar compliance schedules and post-combustion control retrofit installations have been realized successfully in prior programs allowing similar timeframes. Subsequent to the NO_X SIP Call and the parallel Finding of Significant Contribution and Rulemaking on Section 126 Petitions (which became effective December 28, 1998, and February 17, 2000, respectively[278]), nearly 19 GW of SCR retrofit came online in 2002 and another 42 GW of SCR retrofit came online for steam boilers in 2003, illustrating that a considerable volume of SCR retrofit capacity is possible within a 36-month period.

Comment: Some commenters disagreed with EPA's proposed 36-month timeframe for SCR retrofit. These commenters noted that, while possible at the unit or plant level, the collective volume of assumed SCR installation would not be possible given the labor constraints, supply constraints, and simultaneous outages necessary to complete SCR retrofit projects on such a schedule. They noted that many of the remaining coal units lacking SCR pose more site-specific installation challenges than those that were already retrofitted on a quicker timeframe.

Response: EPA is making several changes in this final rule to address these concerns. First, EPA is phasing in emissions reductions commensurate with assumed SCR installations consistent with a 36-to-48-month time frame in this final rule, instead of a 36-month time frame as proposed. EPA is implementing half of this emissions reduction potential in 2026 ozone-season NO_X budgets for states containing these EGUs and the other half of this emissions reduction potential in 2027 ozone-season NO_X budgets for those states. This phase-in approach to implementing SCR retrofit reduction potential over a three to four year period is in response to comments, including those from third-party full-service engineering firms. These commenters highlighted that while the

[274] 958 F.3d at 1203–1204 (remanding the EPA denial of section 126 petition based on the EPA analysis of downwind air quality in 2023 rather than 2021, the year containing the Marginal area attainment date).

[275] 938 F.3d at 317–318. For example, the court observed that the EPA may shorten the deadline for SIP submissions under CAA section 110(a)(1) and may issue FIPs soon thereafter under CAA section 110(c)(1), to align the upwind states' deadline for satisfying good neighbor obligations with the downwind states' deadline for attaining the NAAQS. *Id.* at 318.

[276] *Id.* at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

[277] Compliance by the August 3, 2021, Marginal area attainment date is also impossible as that date has passed.

[278] *See* 63 FR 57356 (October 27, 1998); 65 FR 2674 (January 18, 2000). The D.C. Circuit stayed the NO_X SIP Call by an order issued May 25, 1999. After upholding the rule in most respects in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), the court lifted the stay by an order issued June 22, 2000.

proposed 36-month time frame is viable at the plant level, it would be ''very unlikely'' that the collective volume of SCR capacity could be installed in a three-year time frame based on a variety of factors. First, the commenters identified constraints on labor needed to retrofit 32 GW of capacity, highlighting that the Bureau of Labor and Statistics projects that there will be a decline in boilermaker employment over the decade and that the Associated Builders and Contractors (ABC) identifies the need for 650,000 additional skilled craft professionals on top of the normal hiring pace to meet the economy-wide demand created by infrastructure investment and other clean energy projects (*e.g.,* carbon capture and storage). They highlighted the decline in companies serving this type of large-scale retrofit project as the lack of new coal units and the retirement of coal units has curtailed activity in this area over the past five years. They also identified supply bottlenecks for key SCR components that would slow the ability to implement a large volume of SCR within 3 years, affecting electrical conduits, transformers, piping, structural and plate steel, and wire (with temporary price increases ranging from 30 percent to 200 percent). Finally, commenters note that site-specific conditions can make retrofits for individual units a lengthier process than historical averages (*e.g.,* under prior rules more accommodating sites retrofitted first) and that four years may be necessary for some projects, accordingly. EPA found the technical justification submitted in comment consistent with its prior assessments that a range of 39–48 months is appropriate for SCR-retrofit timing within regional-scale programs.[279] Therefore, EPA is adjusting the timeframe to still incentivize these reductions by the attainment date while accommodating the potential for some SCR retrofits to require between 36–48 months for installation.

Some commenters requested more than 48 months for SCR installation based on past projects that took five or more years. EPA disagrees with these commenters for two reasons. First, while EPA is identifying SCR retrofit potential to define significant contribution at Step 3, the rule only requires emissions reductions commensurate with that technology, implemented through a trading program, meaning that operators of EGUs eligible for SCR retrofit may pursue a variety of strategies for reducing emissions. Such compliance flexibility will accommodate extreme or unique circumstances in which a desired SCR retrofit is not achieved by the 2027 ozone season, although EPA finds such a circumstance exceedingly unlikely. Second, the historical examples that exceeded 48 months do not necessarily demonstrate that such projects are impossible to execute in less than 48 months, but rather that they can extend beyond that timeframe if no requirements or incentives are in place for a faster installation. As the D.C. Circuit has recognized, historical data on the amount of time sources have taken to install pollution controls do not in themselves establish the minimum amount of time in which those controls could be installed if sources are subject to a legal mandate to do so. *See Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes show is that installation can drag on when companies are unconstrained by the ticking clock of the law.'').

b. Non-EGU or Industrial Source Schedule for 2026 and Later Years

The EPA proposed to require that all emissions reductions associated with the requirements for non-EGU industrial sources go into effect by the start of the 2026 ozone season, but also requested comment on its control-installation timing estimates for non-EGUs and requested comment on the possibility of providing for limited compliance extensions based on a showing of necessity. *See* 87 FR 20104–05.

Comment: The EPA received numerous comments regarding the inability of various non-EGU industries to install controls to comply with the emissions limits by 2026. Specifically, commenters raised concerns regarding the ability to meet these deadlines due to the ongoing geopolitical instability triggered by the war in Ukraine, COVID–19 pandemic-driven disruptions, and supply chain delays and shortages. Commenters also claimed that the EPA's three-year installation timeframe for non-EGUs does not account for the time needed to obtain necessary permits. Commenters stated that even where controls are feasible for a source, some sources would need to shut down due to their inability to install controls by 2026 and requested that the EPA provide additional time for sources to come into compliance. Commenters from multiple non-EGU industries stated that the proposed applicability criteria will require controls to be installed on thousands of non-EGU emissions units. Because of the number of emissions units, commenters raised concerns with permitting delays and the unavailability of skilled labor and necessary components. Commenters suggested various timelines for control installation timing ranging from one additional year to seven years. Other commenters asserted that the data supported the conclusion that all non-EGU sources, or at least some non-EGU sources, could install controls by 2026 or earlier, and that EPA has a legal obligation to impose good neighbor requirements as expeditiously as practicable by such sources, including earlier than 2026 if possible.

Response: After reviewing the information received during the public comment period and the additional information presented in the Non-EGU Control Installation Timing Report, the EPA has concluded that the majority of non-EGUs can install and operate the required controls by the 2026 ozone season. For the non-EGU control requirements on which the EPA has based its Step 3 findings as described in section V of this document, the emissions limits will generally go into effect starting with the 2026 ozone season (except where an individual source qualifies for a limited extension of time to comply based on a specific demonstration of necessity, as described in this section). The EPA finds that meeting the emissions limitations of this final rule through installation of necessary controls by an ozone season before 2026 is not expected to be possible for the industrial sources covered by this final rule.

The EPA recognizes that labor shortages, supply shortages, or other circumstances beyond the control of source owner/operators may, in some cases, render compliance by 2026 impossible for a particular industrial source. Therefore, the final rule contains provisions allowing source owner/operators to request limited compliance extensions based on a case-by-case demonstration of necessity. Under these provisions, the owner or operator of a source may initially apply for an extension of up to one year to comply with the applicable emissions control requirements, which if approved by the EPA, would require compliance no later than the 2027 ozone season. The EPA may grant an additional case-based extension of up to two additional years for full compliance, where specific criteria are met.

The EPA initiated a study to examine the time necessary to install the potential controls identified in the final rule's cost analysis for all of the non-EGU industries subject to the final rule, including SNCR, low NO_X burners, layered combustion, NSCR, SCR, fluid gas recirculation, and SNCR/advanced selective noncatalytic reduction

[279] 86 FR 23102.

(ASNCR). The resulting report, which we refer to as the ''Non-EGU Control Installation Timing Report,'' identified a range of estimated installation times with minimum estimated installation times ranging from 6–27 months without any supply chain delays and 6–40 months with potential supply chain delays depending on the industry.[280] The Non-EGU Control Installation Timing Report also identified maximum estimated installation times ranging from 12–28 months without any supply chain delays and 12–72 months with potential supply chain delays depending on the industry. As indicated in the Non-EGU Control Installation Timing Report, the installation of layered combustion and NSCR control technology, in particular, could take between 9 and 72 months depending on supply chain delays.[281] The report also indicated that permitting processes may take 6 to 12 months but noted that these processes typically can proceed concurrent with other steps of the installation process.[282]

We find that the potential time needed for permitting processes is generally unlikely to significantly affect installation timeframes of at least three years given that a source that has three or more years to comply is expected, in most cases, to have adequate time to apply for and secure the necessary permits during that time. Permitting processes may, however, impact shorter installation times ranging from 12–28 months. Given the 12–28 month estimate for minimum and maximum installation times without supply chain delays and permitting timeframes typically ranging from 6–12 months, the EPA finds that the controls for non-EGU sources needed to comply with this final rule are generally not expected to be installed significantly before the 2026 ozone season.

Generally, the Non-EGU Control Installation Timing Report indicated that all non-EGU unit types subject to the final rule could install controls within 28 months if there are no supply chain delays. Thus, the Non-EGU Control Installation Timing Report confirms that for any individual facility, meeting the emissions limitations of this final rule through installation of controls can be completed by the start of the 2026 ozone season. It is only when the number of units in the U.S. potentially affected by the rule is taken into account, coupled with broader considerations of economic capacity including current information on supply-chain delays, that the potential need for additional time beyond 2026 becomes a possibility. Under ideal economic conditions (*i.e.,* no supply-chain delays or other constraints), affected units are estimated to be capable to install both combustion and post-combustion controls before the 2026 ozone season. Many commenters, however, provided information on installation timing estimates based on current supply chain delays and labor constraints. These commenters generally stated that installation of the necessary controls for some units would take longer than three years if supply chain delays similar to those that have occurred over the past few years continue. The Non-EGU Control Installation Timing Report reflected this information, together with additional information gathered from pollution control vendors, to develop ranges of estimates of possible installation times given current (*i.e.,* 2022) labor market conditions and material supplies. The Non-EGU Control Installation Timing Report also discussed how the installation and optimization of post-combustion controls over a similar timeframe at both EGUs and non-EGUs subject to this final rule would, considered cumulatively, potentially affect the installation timing needs of the covered non-EGU sources.

Based on information provided by commenters and vendors, the Non-EGU Control Installation Timing Report indicated that if current supply chain delays continue, control installations could take as long as 61 months for most non-EGU industries and possibly as long as 64–112 months in difficult cases. Notably, however, the conclusions in the Non-EGU Control Installation Timing Report reflect three key assumptions that could result in the relatively lengthy timing estimates at the outer end of this range: (1) the current state of supply chain delays and disruptions would continue without any increase in labor supply, materials, or reduction in fabrication timing; (2) the labor and materials markets would not adjust in response to this rule in the timeframe needed to meet the increased demand for control installations; and (3) the Report was unable to account for some of the flexibilities built into the final rule that will allow owners and operators to install controls on the most cost-effective units with shorter installation times.

As presented in the Non-EGU Control Installation Timing Report, supply chain delays and disruptions have generally been lessening since they peaked in 2020 during the COVID–19 pandemic, and many economic indicators have showed some improvement towards pre-pandemic levels, including freight transportation, inventory to sales ratios, interstate miles traveled, U.S. goods imports, and supply chain indices.[283] If these economic indicators continue to improve and the availability of fabricators and materials continues to trend upward, the control timing estimates identified in the Non-EGU Control Installation Timing Report could prove to be overstated for some industries and control technologies. In addition, the Non-EGU Control Installation Timing Report did not account for the labor and supply market adjustments that would be anticipated to occur to meet increased demand for control technologies and related materials and labor over the next several years in response to the rule. *Cf. Wisconsin,* 938 F.3d at 330 (''[A]ll those anecdotes [of elongated control installation times] show is that installation can drag on when companies are unconstrained by the ticking clock of the law.''). For example, some of the longer installation timeframes identified in the Non-EGU Control Installation Timing Report are based on assumed limits on the current availability of skilled labor needed to install combustion controls and post combustion controls. If the market adjusts in response to increasing demand for this type of skilled labor in the timeframe needed for compliance (*e.g.,* there is an increase in boilermaker and engine controls labor), the installation timing estimates in the Non-EGU Control Installation Timing Report again could be overstated.

The Non-EGU Control Installation Timing Report also did not account for flexibilities provided in this final rule that will enable owners and operators of certain affected units to identify the most cost-effective and efficient means for installing any necessary controls. For example, one concern highlighted by commenters was the amount of time necessary to install controls on engines that have been in operation for 50 or more years. The requirements that we are finalizing for engines in the Pipeline Transportation of Natural Gas industry include an exemption for emergency engines and provisions allowing source owner/operators to request the EPA approval of facility-wide emissions averaging plans, both of which enable owners and operators of affected units to take costs, installation timing needs,

[280] *See generally* SC&A, *NO_X Emission Control Technology Installation Timing for Non-EGU Sources* (March 14, 2023) (''Non-EGU Control Installation Timing Report'').

[281] *See* Non-EGU Control Installation Timing Report, Executive Summary (March 14, 2023).

[282] Id. at Section 5.6.

[283] Id. at Section 6.1.

and other considerations into account in deciding which engines to control.

In response to industry concern about the number and size of units captured by the proposed applicability criteria, the EPA has made several changes to the applicability criteria in the final rule to focus the control requirements on impactful non-EGU units. As explained further in section VI.C of this document, the EPA is establishing exemptions for low-use boilers and engines where it would not be cost-effective to require controls at this time. Finally, as discussed in section VI.C.3 of this document, the EPA is not finalizing the proposed requirements for most emissions unit types in the Iron and Steel Mills and Ferroalloy Manufacturing industry given the EPA does not currently have a sufficient technical basis for finalizing those proposed requirements. These changes reduce the number of non-EGU units that will actually need to install controls and should reduce the strain on the labor and supply chain and permitting processes. For example, for engines, the EPA estimates that the facility-wide emissions averaging provision would, in many cases, allow facilities to install controls on only one-third of their engines, on average (see section VI.C.1 of this document for further discussion).

Taking all of these considerations into account, the EPA finds that the outer range of timing estimates presented in the Non-EGU Control Installation Timing Report generally reflects a conservative set of installation timing estimates and that the factors described previously could result in installation timeframes that fall toward the shorter end of the ranges of time that factor in supply-chain delays or could obviate those supply-chain delay issues entirely.

Based on all of these considerations, the EPA has concluded that three years is generally an adequate amount of time for the non-EGU sources covered by this final rule to install the controls in the 20 states that remain linked in 2026. The EPA also recognizes, however, that some sources may not be able to install controls by the 2026 ozone season despite making good faith efforts to do so, due to the aforementioned supply chain delays or other circumstances entirely beyond the owner or operator's control. Therefore, the final FIPs require compliance with the emissions control requirements for non-EGUs by the beginning of the 2026 ozone season, with limited exceptions based on a showing of necessity for individual sources that meet specific criteria. Where an individual owner or operator submits a satisfactory demonstration that an extension of time to comply is necessary, due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by May 1, 2026, the EPA may determine that installation by 2026 is not possible and thereby grant an extension of up to one year for that source to fully implement the required controls. If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply by the extended compliance date due to circumstances entirely beyond the owner or operator's control and despite all good faith efforts to install the necessary controls by the extended compliance date, the owner or operator may request and the EPA may grant a second extension of up to two additional years for full compliance, where specific criteria are met. This application process is generally in accordance with the concept on which the Agency requested comment in the proposal, *see* 87 FR 20104–05, and is modeled on a similar process provided for industrial sources subject to CAA section 112 NESHAPs, found at 40 CFR 63.6(i)(3).

The EPA intends to grant a request for an initial compliance extension only where a source demonstrates that it has taken all steps possible to install the necessary controls by the applicable compliance date and still cannot comply by the 2026 ozone season, due to circumstances entirely beyond its control. Any request for a compliance extension must be received by the EPA at least 180 days before the May 1, 2026, compliance date. The request must include all information obtained from control technology vendors demonstrating that the necessary controls cannot be installed by the applicable compliance date, any permit(s) secured for the installation of controls or information from the permitting authority on the timeline for issuance of such permit(s) if the source has not yet obtained the required permit(s); and any contracts entered into by the source for the installation of the control technology or an explanation as to why no contract is necessary. The EPA may also consider documentation of a source owner's/operator's plans to shut down a source by the 2027 ozone season in determining whether a source is eligible for a compliance extension. The owner or operator of an affected unit remains subject to the May 1, 2026 compliance date unless and until the Administrator grants a compliance extension.

The EPA intends to grant a request for a second compliance extension beyond 2027 only where a source owner/operator submits updated documentation showing that it is not possible to install and operate controls by the 2027 ozone season, despite all good faith efforts to comply and due to circumstances entirely beyond its control. The request must be received by the EPA at least 180 days before the extended compliance date and must include, at minimum, the same types of information as that required for the initial extension request. The owner or operator of an affected unit remains subject to the initial extended compliance date unless and until the Administrator grants a second compliance extension. A denial will be effective on the date of denial.

As discussed earlier in section VI.A, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity.'' [284] This standard is met when, in the EPA's judgment, compliance by the attainment date amounts to an impossibility. The EPA cannot allow a covered industrial source to avoid timely compliance with the emissions control requirements established in this final rule unless the source owner/operator can demonstrate that compliance by the 2026 ozone season is not possible due to circumstances entirely beyond their control. The criteria that must be met to qualify for limited extensions of time to comply are designed to meet this statutory mandate. The EPA anticipates that the majority of the industrial sources covered by this final rule will not qualify for a compliance extension.

B. Regulatory Requirements for EGUs

To implement the required emissions reductions from EGUs, the EPA is revising the existing CSAPR NO_X Ozone Season Group 3 Trading Program (the ''Group 3 trading program'') established in the Revised CSAPR Update both to expand the program's geographic scope and to enhance the program's ability to ensure favorable environmental outcomes. The EPA is using a trading program for EGUs because of the inherently greater flexibility that a trading program can provide relative to more prescriptive, ''command-and-control'' forms of regulation of sufficient stringency to achieve the necessary emissions reductions. In the electric

[284] *Wisconsin,* 938 F.3d at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

power sector, EGUs' extensive interconnectedness and coordination create the ability to shift both electricity production and emissions among units, providing a closely related ability to achieve emissions reductions in part by shifting electricity production from higher-emitting units to lower-emitting or non-emitting units. Thus, while the Step 3 control-stringency determination for EGUs to eliminate significant contribution is based on strategies that do not require generation shifting or reduced utilization of EGUs, the sector's unusual flexibility with respect to how emissions reductions can be achieved makes the flexibility of a trading program particularly useful as a means of lowering the overall costs of obtaining such reductions. In addition, it is essential for the electric power sector to retain short-term operational flexibility sufficient to allow electricity to be produced at all times in the quantities needed to meet demand simultaneously, and the flexibility of a trading program can be helpful in supporting this aspect of the industry as well.

To ensure emissions reductions necessary to eliminate significant contribution are maintained, in this rulemaking, the EPA is making certain enhancements to the current provisions of the Group 3 trading program addressing emissions-control performance by some kinds of individual units that will necessarily reduce the flexibility of the program to some extent for those units. In analyzing significant contribution at Step 3, once a linkage has been established between an upwind state and a downwind receptor, we identify an appropriate set of emissions control strategies, considering cost and other factors, that would eliminate significant contribution from the upwind state without leading to undercontrol or overcontrol at the downwind linked receptors. At Step 4, for EGUs, we develop emissions budgets based on consistent application of the identified strategies to the sources. This level of emission control at each source identified in Step 3 is what the EPA deems to eliminate significant contribution, while the design of emission budgets that successfully implement that level of emission control is determined at Step 4. See section III.B and V.

The trading program enhancements discussed in this section are designed to ensure that sources actually achieve that level of emission control and thereby eliminate significant contribution on a permanent basis at Step 4. The enhancements ensure that the emissions budgets for EGUs continue to secure the level of emission control identified at Step 3 at the sources active in the trading program on a more consistent basis throughout each ozone season than prior transport trading programs (including those that did not provide complete remedies for interstate pollution transport) have required. An alternative form of implementation at Step 4 would be to implement source-specific emissions limitations (*e.g.,* rate-based standards expressed as mass per unit of heat input) reflecting the control strategies identified at Step 3. This is a very common form of implementation for many other CAA requirements and is indeed the manner of implementation selected in this very rulemaking for other affected industrial sources. See sections III.B, V.D.4, and VI.C. But doing so would require loss of the flexibilities inherent in a trading program, inclusive of these enhancements, that facilitate orderly and timely achievement of the required emission reductions in the power sector.

Prior to this rule, the Group 3 trading program has applied to EGUs meeting the program's applicability criteria within the borders of twelve states: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs in these twelve states will continue to participate in the Group 3 trading program as revised in this rulemaking, with some revised provisions taking effect in the 2023 control period and other revised provisions taking effect later as discussed elsewhere in this document. The EPA is expanding the Group 3 trading program's geographic scope to include all of the additional states for which EGU emissions reduction requirements are being established in this rulemaking. Affected EGUs within the borders of seven states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—will transition from the Group 2 trading program to the revised Group 3 trading program at the beginning of the 2023 control period,[285] and affected EGUs within the borders of the three states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Minnesota, Nevada, and Utah—will enter the Group 3 trading program in the 2023 control period on the effective date of this rule. As discussed in section VI.B.12.a of this document, because the effective date of the rule will likely be sometime during the 2023 ozone season, special transitional provisions have been developed to allow for efficient administration of the rule's EGU requirements through the Group 3 trading program while not imposing any new substantive obligations on parties prior to the rule's effective date, similar to the transitional provisions implemented under the Revised CSAPR Update.

As is the case for the states already in the Group 3 trading program, for each state added to the program, the set of affected EGUs will include new units as well as existing units and will also include units located in Indian country within the state's borders. Sections VI.B.2 and VI.B.3 of this rule provide additional discussion of the geographic expansion of the Group 3 trading program and the units in the expanded geography that will become subject to the program under the program's existing applicability provisions.

In addition to expanding the Group 3 trading program's geographic scope, the EPA is modifying the program's regulations prospectively to include certain enhancements to improve environmental outcomes. Two of the proposed enhancements will adjust the overall quantities of allowances available for compliance in the trading program in each control period so as to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves. First, instead of establishing emissions budgets for all future years under the program at the time of the rulemaking, which cannot reflect future changes in the EGU fleet unknown at the time of the rulemaking, the EPA is revising the trading program regulations to include a dynamic budgeting procedure. Under this procedure, the EPA will calculate emissions budgets for control periods in 2026 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2024 ozone season and following (*e.g.,* for 2026, data from periods through 2024; for 2027, data from periods through 2025; etc.). Through the 2029 control period, the dynamically determined budgets will apply only if they are higher than preset budgets established in the rule. (Associated revisions to the program's variability limits and unit-level allowance allocation procedures will coordinate these provisions with the revised budget-setting procedures.) Second,

[285] Affected EGUs in the three other states currently covered by the Group 2 trading program—Iowa, Kansas, and Tennessee—will continue to participate in that program.

starting with the 2024 control period, the EPA will annually recalibrate the quantity of accumulated banked allowances under the program to prevent the quantity of allowances carried over from each control period to the next from exceeding the target bank level, which would be revised to represent a preset percentage of the sum of the state emissions budgets for each control period. The preset percentage will be 21 percent for control periods through 2029 and 10.5 percent for control periods in 2030 and later years. Together, these enhancements will protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and will better sustain over time the incentives created by the trading program to achieve the degree of emissions control for EGUs that the EPA has determined is necessary to address states' good neighbor obligations.

Two further enhancements to the Group 3 trading program establish provisions designed to promote more consistent emissions control by individual EGUs within the context of the trading program. First, starting with the 2024 control period for coal-fired EGUs with existing SCR controls and the earlier of the 2030 control period or the control period after which an SCR is installed for other large coal-fired EGUs, a daily NO_X emissions rate of 0.14 lb/mmBtu will apply as a backstop to the seasonal emissions budgets (which are based on an assumed seasonal average emissions rate of 0.08 lb/mmBtu for EGUs with existing SCR controls). Each ton of emissions exceeding a unit's backstop daily emissions rate, after the first 50 such tons, in a given control period will incur a 3-for-1 allowance surrender ratio instead of the usual 1-for-1 allowance surrender ratio. Second, also starting with the 2024 control period, the trading program's existing assurance provisions, which require extra allowance surrenders from sources that are found responsible for contributing to an exceedance of the relevant state's ''assurance level'' (*i.e.,* typically 121 percent of the state's emissions budget), will be strengthened by the addition of another backstop requirement. Specifically, for any unit equipped with post-combustion controls that is found responsible for contributing to an exceedance of the state's assurance level, the revised regulations will prohibit the unit's seasonal emissions from exceeding by more than 50 tons the emissions that would have resulted if the unit had achieved a seasonal average emissions rate equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest previous seasonal average emissions rate under any CSAPR seasonal NO_X trading program.[286]

These two enhancements are designed to ensure that all individual units with SCR controls have strong incentives to continuously operate and optimize their controls, and also to ensure that all units with post-combustion controls have strong incentives to optimize their emissions performance when a state's assurance level might otherwise be exceeded. These enhancements are generally designed to ensure consistency with the EPA's determination regarding the emissions control stringency needed from EGUs to eliminate significant contribution under the Step 3 multifactor analysis as discussed in section V of this document. Further, these enhancements are designed to provide greater assurance that emissions controls will be operated on all days of the ozone season and therefore necessarily on the days that turn out to be most critical for downwind ozone levels. The EPA expects that promoting more consistently good emissions performance by individual EGUs will better ensure that each state's significant contribution is fully eliminated by this action, *see North Carolina,* 531 F.3d at 919–21. In addition to addressing the statutory requirements of eliminating significant contribution, the EPA anticipates that these enhancements will also deliver public health and environmental benefits to underserved and overburdened communities.

The revisions to the Group 3 trading program being finalized in this rule are very similar to the proposed revisions. The changes from proposal to the set of states covered are driven largely by updates to the air quality modeling performed for the final rule, as described in section IV of this document. The changes from proposal to the trading program enhancements are generally being made in response to comments on the proposal, as discussed in more detail in the remainder of section VI.B of this document.

[286] The requirement would not apply for control periods during which the unit operated for less than 10 percent of the hours, and emissions rates achieved in such previous control periods would be excluded from the comparison.

1. Trading Program Background and Overview of Revisions

a. Current CSAPR Trading Program Design Elements and Identified Concerns

The use of allowance trading programs to achieve required emissions reductions from the electric power sector has a long history, rooted in the Clean Air Act Amendments of 1990. In Title IV of those amendments, Congress specified the design elements for a 48-state allowance trading program to reduce SO_2 emissions and the resulting acid precipitation. Building on the success of that first allowance trading program as a tool for addressing multi-state air pollution issues, since 1998 EPA has promulgated and implemented multiple allowance trading programs for SO_2 or NO_X emissions to address the requirements of the CAA's good neighbor provision with respect to successively more protective NAAQS for fine particulate matter and ozone. Most of these trading programs have applied either exclusively or primarily to EGUs.

The EPA currently administers six CSAPR trading programs for EGUs (promulgated in CSAPR, the CSAPR Update, and the Revised CSAPR Update) that differ in the pollutants, geographic regions, and time periods covered and in the levels of stringency, but that otherwise have been nearly identical in their core design elements and their regulatory text.[287] The principal common design elements currently reflected in all of the programs are as follows:

- An ''emissions budget'' is established for each state for each control period, representing the EPA's quantification of the emissions that would remain under certain projected conditions after elimination of the emissions prohibited by the good neighbor provision under those projected conditions. For each control period of program operation, a quantity of newly issued ''allowances'' equal to the amount of each state's emissions budget is allocated among the state's sources. (States have options to replace the EPA's default allocations or to institute an auction process.) Total emissions in a given control period from all sources in the program are effectively

[287] The six current CSAPR trading programs are the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR SO_2 Group 1 Trading Program, CSAPR SO_2 Group 2 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR NO_X Ozone Season Group 3 Trading Program. The regulations for the six programs are set forth at subparts AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97.

capped at a level no higher than the total quantity of allowances available for use in the control period, consisting of the sum of all states' emissions budgets for the control period plus any unused allowances carried over from previous control periods as ''banked'' allowances.

• ''Assurance provisions'' in each program establish an ''assurance level'' for each state for each control period, defined as the sum of the state's emissions budget plus a specified ''variability limit.'' The purpose of the assurance provisions is to limit the total emissions from each state's sources in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's mandate that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability. In the event a state's assurance level is exceeded, responsibility for the exceedance is apportioned among the state's sources through a procedure that accounts for the sources' shares of the state's total emissions for the control period as well as the sources' shares of the state's assurance level for the control period.

• At the program's compliance deadlines after each control period, sources are required to hold for surrender specified quantities of allowances. The minimum quantities of allowances that must be surrendered are based on the sources' reported emissions for the control period at a 1-for-1 ratio of allowances to tons of emissions (or 2-for-1 in instances of late compliance). In addition, two more allowances must be surrendered for each ton of emissions exceeding a state's assurance level for a control period, yielding an overall 3-for-1 surrender ratio for those emissions (or 4-for-1 in instances of late compliance). Failure to timely surrender all required allowances is potentially subject to penalties under the CAA's enforcement provisions.

• To continuously incentivize sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, and to promote compliance cost minimization, operational flexibility, and allowance market liquidity, the programs allow trading of allowances—both among sources in the program and with non-source entities—and also let allowances that are unused in one control period be carried over for use in future control periods as banked allowances. Although the CSAPR programs do not limit trading of allowances, and prior to this rule have not limited banking of allowances within a given trading program, the 3-for-1 surrender ratio imposed by the assurance provisions on any emissions exceeding a state's assurance level disincentivizes sources from relying on either in-state banked allowances or net out-of-state purchased allowances to emit over the assurance level.[288]

• Finally, other common design elements ensure program integrity, source accountability, and administrative transparency. Most notably, each unit must monitor and report emissions and operational data in accordance with the provisions of 40 CFR part 75; all allowance allocations or auction results, transfers, and deductions must be properly recorded in the EPA's Allowance Management System; each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account; and comprehensive data on emissions and allowances are made publicly available.

The EPA continues to believe that the historical CSAPR trading program structure established by the common design elements just described has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide to a sector such as the electric power sector where such flexibility is especially useful and valuable. However, the EPA also shares many stakeholders' concerns about whether the historical structure, without enhancements, is capable of adequately addressing states' good neighbor obligations with respect to the 2015 ozone NAAQS in light of the rapidly evolving EGU fleet and the protectiveness and short-term form of the ozone standard. One set of concerns relates to the historically observed tendency under the trading programs for the supply of allowances to grow over time while the demand for allowances falls, reducing allowance prices and eroding the consequent incentives for sources to effectively control their emissions. A second, overlapping set of concerns relates to the general absence of source- or unit-specific emissions reduction requirements, allowing some individual sources to idle or run less optimally existing emissions controls even when a linkage between the sources' state and a receptor persists. For example, certain units in Ohio and Pennsylvania have been found to have operated their controls below target emissions performance levels used for budget setting under the CSAPR Update in the 2019–2021 period, even though the Revised CSAPR Update found that these states remained linked through at least 2021 to receptors for the 2008 ozone NAAQS, and the CSAPR Update itself was only a partial remedy. *See* 86 FR 23071, 23083. While this unit-level behavior may have been permissible under the prior program, emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard. This indicates that the prior program design was not effectively ensuring the elimination of significant contribution.[289]

The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. In an effort to ensure emissions control on critically important highest ozone days, guard against non-operation of emissions controls under a more protective NAAQS, and provide assurance of elimination of significant contribution to downwind areas, while also maintaining appropriate compliance and operational flexibility for EGUs, the EPA in this rule is implementing a suite of enhancements to the trading program. These will help to ensure reductions occur on the highest ozone days commensurate with our Step 3 determinations, in addition to maintaining a mass-based seasonal requirement. To meet the statutory mandate to eliminate significant contribution and interference with

[288] As discussed in section VI.B.6 of this document, while allowance banking has not previously been limited under any of the CSAPR trading programs, limits on the use of banked allowances were included in the earlier NO_X Budget Trading Program in the form of ''flow control'' provisions.

[289] We also observe that these sources' emissions have the potential to impact downwind overburdened communities. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E. The EPA conducted a screening-level analysis to determine whether there may be impacts on overburdened communities resulting from those EGUs receiving backstop emissions rates under this rule. This analysis identified a greater potential for these sources to affect areas of potential concern than the national coal-fired EGU fleet on average. However, this analysis is distinct from the more comprehensive exposure analysis conducted as discussed in section VII of this document and the RIA. In addition, we note that our conclusions regarding the EGU trading program enhancements in this final rule are wholly supportable and justified under the good neighbor provision, even in the absence of any potential benefits to overburdened communities.

maintenance on the critically important days, this combination of provisions will strongly incentivize sources to plan to run controls all season, including on the highest ozone days, while giving reasonable flexibility for occasional operational needs.[290]

In this rulemaking, the EPA is revising the Group 3 trading program to include enhancements designed to address both sets of concerns described previously. The principles guiding the various revisions and the relationships of the revisions to one another are discussed in sections VI.B.1.b and VI.B.1.c of this document. The individual revisions are discussed in more detail in sections VI.B.4 through VI.B.9 of this document.

b. Enhancements To Maintain Selected Control Stringency Over Time

The first set of concerns noted about the current CSAPR trading program structure relates to the programs' ability to maintain the rule's selected control stringency and related EGU effective emissions performance level as the EGU fleet evolves over time. Under the historical structure of the CSAPR trading programs, the effectiveness of the programs at maintaining the rule's selected control stringency depends entirely on how allowance prices over time compare to the costs of sources' various emissions reduction opportunities, which in turn depends on the relationship between the supply for allowances and the demand for allowances. In considering possible ways to address concerns about the ability to enhance the historical trading program structure to better sustain incentives to control emissions over time, the EPA has focused on the trading program design elements that determine the supply of allowances, specifically the approach for setting state emissions budgets and the rules concerning the carryover of unused allowances for use in future control periods as banked allowances.

i. Revised Emissions Budget-Setting Process

In each of the previous rulemakings establishing CSAPR trading programs, the EPA has evaluated the emissions that could be eliminated through implementation of certain types of emissions control strategies available at various cost thresholds to achieve certain rates of emissions per unit of heat input (*i.e.,* the amount of fuel consumed) and the effects of the resulting emissions reductions on downwind air quality. After determining the emissions control strategies and associated emissions reductions that should be required under the good neighbor provision by considering these factors in a multifactor test at Step 3, the EPA has then for purposes of Step 4 implementation program design projected the amounts of emissions that would remain after the assumed implementation of the selected emissions control strategies at various points in the future and has established the projected remaining amounts of emissions as the state emissions budgets in trading programs.

Projecting the amounts of emissions remaining after implementation of selected emissions controls necessarily requires projections not only for sources' future emissions rates but also for other factors that influence total emissions, notably the composition of the future EGU fleet (*i.e.,* the capacity amounts of different types of sources with different emissions rates) and their future utilization levels (*i.e.,* their heat input). To the extent conditions unfold in practice that differ from the projections made at the time of a rulemaking for these other factors, over time the emissions budgets may not reflect the intended stringency of the emissions control strategies identified in the rulemaking as consistent with addressing states' good neighbor obligations. Further, projecting EGU fleet composition and utilization beyond the relatively near-term analytic years of 2023 and 2026 given particular attention in this rulemaking has become increasingly challenging in light of the anticipated continued evolution of the electric power sector toward more efficient and cleaner sources of generation, including as driven by incentives provided by the Infrastructure Investment and Jobs Act as well as the Inflation Reduction Act.

A consequence of using a trading program approach with preset emissions budgets that do not keep pace with the trends in EGU fleet composition and heat input is that the preset emissions budgets maintain the supply of allowances at levels that increasingly exceed the emissions that would occur even without implementation of the emissions control strategies used as the basis for determining the emissions budgets, causing decreases in allowance prices and hence the incentives to implement the control strategies. As an example, although the emissions budgets in the CSAPR Update established in 2016 reflected implementation of the emissions control strategy of operating and optimizing existing SCR controls, within four years the EPA found that EGU retirements and changes in utilization not anticipated in EPA's previous budget-setting computations had made it economically attractive for at least some sources to idle or reduce the effectiveness of their existing controls (relying on purchased allowances instead).[291] While the EPA has provided analysis indicating that, on average, sources operate their controls more effectively on high electric demand days, it has also identified cases where units fail to optimize their controls on these days. Downwind states have suggested this type of reduced pollution control performance has occurred on the day and preceding day of an ozone exceedance.[292] [293] While the EPA had previously provided analysis focusing on the year of initial program implementation, when allowance prices were high (*i.e.,* 2017 for the CSAPR Update), to demonstrate that on average, sources operate their controls more effectively on high electric demand days, even in that case it had identified situations where particular units failed to optimize their controls on these days. In later years, when allowance prices had fallen, more sources, including some identified by commenters, had idled or reduced the effectiveness of their controls. Such an outcome undermined the ongoing achievement of emissions rate performance consistent with the control strategies identified in the CSAPR Update to eliminate significant contribution to nonattainment and interference with maintenance, despite the fact that the mass-based budgets were being met.

In the Revised CSAPR Update, the EPA took steps to better address the rapid evolution of the EGU fleet, specifically by setting updated emissions budgets for individual future

[290] Deferral of the backstop daily emissions rate for certain EGUs, for reasons discussed in section VI.B.7 of this document, does not alter this finding that this trading program enhancement is an important part of the solution to eliminating significant contribution from EGUs under CAA section 110(a)(2)(D)(i)(I).

[291] The price of allowances in CSAPR Update states started at levels near $800 per ton in 2017 but declined to less than $100 per ton by 2019 and were less than $70 per ton in July 2020 (data from S&P Global Market Intelligence).

[292] 86 FR 23117.

[293] *See* EPA–HQ–OAR–2020–0272–0094 (''[This] is demonstrated through examination of Maryland's ozone design value days for June 26th–28th, 2019. On those days, Maryland recorded 8-hour ozone levels of 75, 85 and 83 ppb at the Edgewood monitor. Maryland Department of the Environment evaluated the daily NO_X emission rate for units in Pennsylvania that were found to influence the design values on the 3 exceedance days (and 1 day prior to the exceedance) against the past-best ozone season 30-day rolling average optimized NO_X rate (which tends to be higher than the absolute lowest seasonal average rate).'').

years though 2024 that reflect future EGU fleet changes known with reasonable certainty at the time of the rulemaking. Some commenters in that rulemaking requested that the EPA also update the year-by-year emissions budgets to reflect future fleet changes that might become known after the time of the rulemaking, but the EPA declined to do so, in part because no methodology for making future emissions budget adjustments in response to post-rulemaking data had been included in the proposal for the rulemaking.

Based on information available as of December 2022, it appears that the emissions budgets set for the first two control periods covered by the Revised CSAPR Update generally succeeded at creating incentives to operate emissions controls under the Group 3 trading program for those control periods. However, the EPA recognizes that the lack of emissions budget adjustments after 2024 in conjunction with industry trends toward more efficient and cleaner resources will likely lead to a surplus of allowances after the adjustments end. This prospect for the existing Group 3 trading program should be avoided by the changes being made in this rulemaking. In this rulemaking, besides establishing new preset emissions budgets for the 2023 through 2029 control periods, the EPA is also extending the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update to routinely calculate dynamic emissions budgets for each future control period from 2026 on, to be published in the year before that control period, with each dynamic emissions budget generally reflecting the latest available information on the composition and utilization of the EGU fleet at the time that dynamic emissions budget is determined. For the control periods in 2026 through 2029, each state's final emissions budget will be the preset budget determined for the state in this rulemaking except in instances when the dynamic budget determined for the state (and published approximately one year before the control period using the dynamic budget-setting methodology) is higher. For control periods in 2030 and thereafter, the emissions budgets will be the amounts determined for each state in the year before the control period using the dynamic budget-setting methodology.

The current budget-setting methodology established in the Revised CSAPR Update and the revisions being made to that methodology are discussed in detail in section VI.B.4 of this document and the Ozone Transport Policy Analysis Final Rule TSD. To summarize here, the methodology used to determine the preset budgets largely follows the Revised CSAPR Update's emissions budget-setting methodology, which included three primary steps: (1) establishment of a baseline inventory of EGUs adjusted for known retirements and new units, with heat input and emissions rate data for each EGU in the inventory based on recent historical data; (2) adjustment of the baseline data to reflect assumed emissions rate changes resulting from known new controls, known gas conversions, and implementation of the emissions control strategies used to determine states' good neighbor obligations; and (3) application of an increment or decrement to reflect the effect on emissions from projected generation shifting among the units in a state at the emissions reduction cost associated with the selected emissions control strategies. In this rulemaking, the EPA has determined the preset state emissions budgets for the control periods from 2023 through 2029 by using the Revised CSAPR Update's budget-setting methodology, except that the step of that methodology intended to reflect the effects of generation shifting has been eliminated.

The dynamic budget-setting methodology used to determine dynamic state emissions budgets in the year before each control period starting with the 2026 control period is set forth in the revised Group 3 trading program regulations at 40 CFR 97.1010(a). This methodology modifies the Revised CSAPR Update's budget-setting methodology in two ways. First, the baseline EGU inventory and heat input data, but not the emissions rate data, will be updated for each control period using the most recent available reported data in combination with reported data from the four immediately preceding years. For example, in early 2025, using the final data reported for 2020 through 2024, the EPA will update the baseline inventory and heat input data used to determine dynamic state emissions budgets for the 2026 control period.[294] Second, the EPA will not apply an increment or decrement to any state emissions budget for projected generation shifting associated with implementation of the selected control strategies, because any such shifting should already be reflected in the reported heat input data used to update the baseline.

The EPA believes that the revisions to the emissions budget-setting process will substantially improve the ability of the emissions budgets to keep pace with changes in the composition and utilization of the EGU fleet. The dynamic budget-setting methodology will account for the electric power sector's overall trends toward more efficient and cleaner resources, both of which tend to decrease total heat input at affected EGUs, and through 2029 the preset budgets established in the rule will also account for these factors to the extent known. The dynamic budget-setting methodology will also account for other factors that could lead to increased heat input in some states, such as generation shifting from other states or increases in electricity demand caused by rising electrification. The dynamic budget-setting procedure is specified in this final rule's trading program regulations and the computations, which are straightforward, can be performed in a spreadsheet to deliver reliable results. The EPA will provide public notice of the preliminary calculations and the data used by March 1 of the year preceding the control period and will provide an opportunity for submission of any objections to the data and preliminary calculations before finalizing the dynamic budgets for each control period by May 1 of the year before the control period to which those dynamic budgets apply. Thus, for example, sources and other stakeholders will have certainty by May 1, 2025, of the dynamic emissions budgets that will be calculated for the 2026 control period that starts May 1, 2026. Moreover, as of the issuance of this final rule, stakeholders will know the state-level preset emissions budgets for the 2026–2029 control periods, which serve as floors that will only be supplanted by dynamic budgets calculated for those control periods if such a dynamic budget yields a higher amount of tons than the corresponding preset budget established in this action.

It bears emphasis that the annually updated information used in the dynamic budget-setting computations will concern only the composition and utilization of the EGU fleet and not the emissions rate data also used in those computations. The dynamically determined emissions budget computations for all years will reflect only the specific emissions control

[294] As discussed in section VI.B.4 of this document, the state-level data used to determine the overall state-level heat input for computing a state's dynamic budget will be a three-year average (*e.g.,* 2022–2024 state-level data will be used in 2025 to set the 2026 dynamic budgets). The unit-level data used to determine individual units' shares of the state-level heat input in the computations will be the average of the three highest non-zero heat input amounts for the respective units over the most recent five years (*e.g.,* 2020–2024 unit-level data will be used in 2025 to set the 2026 dynamic budgets).

strategies used to determine states' good neighbor obligations as determined in this rulemaking, along with fixed historical emissions rates for units that are not assumed to implement additional control strategies, thereby ensuring that the annual updates will eliminate emissions as determined to be required under the good neighbor provision. The stringency of the emissions budgets will simply reflect the stringency of the emissions control strategies determined in the Step 3 multifactor analysis and will do so more consistently over time than the EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking.

The rule's revisions relating to state emissions budgets and the budget-setting process generally follow the proposal except for two changes we are making in response to comments, specifically: we will use historical data from multiple years rather than a single year in the dynamic budget-setting process, and we are establishing preset emissions budgets for the 2026–2029 control periods such that the dynamic budgets for those control periods will only be imposed where they exceed the corresponding preset budgets finalized in this rule. The rationale for these changes is discussed later in this section as part of the responses to the relevant comments. Details of the final budget-setting methodology and responses to additional comments are discussed further in section VI.B.4 of this document.

The final rule's provisions relating to the determination of state-level variability limits and assurance levels and unit-level allowance allocations are coordinated with the budget-setting methodology. These provisions generally follow the proposal except that the change to the methodology for determining variability limits is implemented starting with the 2023 control period instead of the 2025 control period and the final methodology for determining unit-level allocations of allowances to coal-fired units considers the controlled emissions rate assumptions applicable to the same units in the budget-setting process. Details of these provisions, including the rationales for the changes from proposal, are discussed in sections VI.B.5 and VI.B.9, respectively.

ii. Allowance Bank Recalibration

Besides the levels of the emissions budgets, the second design element of the trading program structure that affects the supply of allowances in each control period, and that consequently also affects the ability of a trading program to maintain the rule's selected control stringency as the EGU fleet evolves over time, is the set of rules concerning the carryover of unused allowances for use in future control periods as banked allowances. As noted previously, trading and banking of allowances in the CSAPR trading programs can serve a variety of purposes: continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. All of these purposes are advanced by rules that allow sources to trade allowances freely (both with other sources and with non-source entities such as brokers). All of these purposes are also advanced by rules that allow unused allowances to be carried over for possible use in future control periods, thereby preserving a value for the unused allowances. However, while the EPA considers it generally advantageous to place as few restrictions on the trading of allowances as possible,[295] unrestricted banking of allowances has a potentially significant disadvantage offsetting its advantages, namely that it allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowance prices and weakens the trading program's incentives to control emissions. With weakened incentives, some operators would be more likely to choose not to continuously operate and optimize their emissions controls, imperiling the ongoing achievement of emissions rate performance consistent with the control strategies defined as eliminating significant contribution to nonattainment and interference with maintenance.

As discussed in detail in section VI.B.6 of this rule, the EPA is revising the Group 3 trading program by adding provisions that establish a routine recalibration process for banked allowances that will be carried out in August 2024 and each subsequent August, after the compliance deadline for the control period in the previous year. In each recalibration, the EPA will reset the total quantity of banked allowances for the Group 3 trading program (''Group 3 allowances'') held in all Allowance Management System accounts to a level computed as a target percentage of the sum of the state emissions budgets for the current control period. The target percentage will be 21 percent for the 2024–2029 control periods and 10.5 percent for control periods in 2030 and later years. The recalibration procedure entails identifying the ratio of the target bank amount to the total quantity of banked allowances held in all accounts before the recalibration and then, if the ratio is less than 1.0, multiplying the quantity of banked allowances held in each account by the ratio to identify the appropriate recalibrated amount for the account (rounded to the nearest allowance), and deducting any allowances in the account exceeding the recalibrated amount.

As noted previously, recalibration of the bank for each control period will be carried out in August of that control period. This timing will accommodate the process of deducting allowances for compliance for the previous control period, which cannot be completed before sources' June 1 compliance deadline for the previous control period, and will then provide approximately two additional months for sources to engage in any desired allowance transactions before recalibration occurs. However, data that can be used to estimate the bank recalibration ratio for each control period will be available shortly after the end of the previous control period, and the EPA will use these data to make information on the estimated bank recalibration ratio for each control period publicly available no later than March 1 of the year of that control period, thereby facilitating the ability of affected EGUs to anticipate their ultimate holdings of recalibrated banked allowances to inform their compliance planning for that control season. Affected EGUs will also have several months following the completed bank recalibration in August to transact allowances with other parties as needed

[295] The advantages of trading programs discussed earlier in this section—providing continuous emissions reduction incentives, facilitating compliance cost minimization, and supporting operational flexibility—depend on the existence of a marketplace for purchasing and selling allowances. Broader marketplaces generally provide greater market liquidity and therefore make trading programs better at providing these advantages. The EPA recognizes that unrestricted use of *net* purchased allowances—meaning quantities of purchased allowances that exceed the quantities of allowances sold—by a source or group of sources as an alternative to making emissions reductions can interfere with the achievement of the desired environmental outcome. Therefore, section VI.B.1.c of this document discusses the enhancements to the Group 3 trading program that the EPA is making in this rulemaking to reduce reliance on net purchased allowances by incentivizing or requiring better environmental performance at individual EGUs. However, the concern arises from the *use of an excessive quantity* of net purchased allowances for a particular purpose, not from the existence of a *marketplace* where allowances may be freely bought and sold.

before the allowance transfer deadline of June 1 of the following year.

The EPA believes this revision to the Group 3 trading program's banking provisions establishing an annual bank recalibration process will complement the revisions to the budget-setting process by preventing any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods.

The calibration procedure will not erase the value of unused allowances for the holder, because the larger the quantity of banked allowances that is held in a given account before each recalibration, the larger the quantity of banked allowances that will be left in the account after the recalibration for possible sale or use in meeting future compliance requirements. Because the banked allowances will always have value, the opportunity to bank allowances will continue to advance the purposes served by otherwise unrestricted banking as described previously. Opportunities to bank unused allowances can serve all these same purposes whether a banked allowance is of partial value (if the bank needs recalibrating to its target level) or is of full value compared to a newly issued allowance for the next control period.

The final rule's provisions relating to bank recalibration generally follow the proposal except that, in response to comments, the target percentage used to determine the recalibrated bank levels for the 2024–2029 control periods is being set at 21 percent instead of 10.5 percent. The rationale for this change is discussed later in this section as part of the responses to the relevant comments. Details of the bank recalibration provisions are discussed further in section VI.B.6 of this rule.

c. Enhancements To Improve Emissions Performance at Individual Units

The second set of concerns about the structure of the current CSAPR trading programs relates to the general absence of source- or unit-specific emissions reduction requirements. Without such requirements, the programs affect individual sources' emissions performance only to the extent that the incentives created by allowance prices are high enough relative to the costs of the sources' various emissions control opportunities. In circumstances where the incentives to control emissions are insufficient, some individual sources even idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard.

This EPA intends that the trading program enhancements described in section VI.B.1.b of this rule will improve the Group 3 trading program's ability to sustain emissions control incentives over time such that needed emissions performance will be achieved by all participating units without the need for additional requirements to be imposed at the level of individual units. However, because obtaining needed emissions performance at individual units is also important to the elimination of significant contribution in keeping with the EPA's Step 3 determinations, the EPA is supplementing the previously discussed enhancements with two other new sets of provisions that will apply to certain individual units within the larger context of the Group 3 trading program. The allowance price will continue to be the most important driver of good environmental performance for most units, but the proposed unit-level requirements will be important supplemental drivers of performance and will offer additional assurance that significant contribution is eliminated on a daily basis during the ozone season by more continuous operation of existing pollution controls.

i. Unit-Specific Backstop Daily Emissions Rates

The first of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of backstop daily NO_X emissions rate provisions that will apply to large coal-fired EGUs, defined for this purpose as units serving electricity generators with nameplate capacities equal to or greater than 100 MW and combusting any coal during the control period in question. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The additional allowance surrender requirement will be integrated into the trading program as a new component in the calculation of each unit's primary emissions limitation, such that the additional allowances will have to be surrendered by the same compliance deadline of June 1 after each control period. The amount of additional allowances to be surrendered will be determined by computing, for each day of the control period, any excess of the unit's reported emissions (in pounds) over the emissions that would have resulted from combusting that day's actual heat input at an average daily emissions rate of 0.14 lb/mmBtu, summing the daily amounts, converting from pounds to tons, computing the amount of any excess over 50 tons, and multiplying by two. Starting with the second control period in which newly installed SCR controls are operational, but not later than the 2030 control period, the 3-for-1 surrender ratio will apply in the same way to all large coal-fired EGUs except circulating fluidized bed units, consistent with EPA's determination that a control stringency reflecting installation and operation of SCR controls on all such large coal-fired EGUs is appropriate to address states' good neighbor obligations with respect to the 2015 ozone NAAQS.

In prior rules addressing interstate transport of air pollution, stakeholders have noted that while seasonal cap-and-trade programs are effective at lowering ozone and ozone-forming precursors across the ozone season, attainment of the standard is measured on key days and therefore it is necessary to ensure that the rule requires emissions reductions not just seasonally, but also on those key days.[296] They have noted that while the trading programs established under the NO_X SIP Call, CAIR, and CSAPR have all been successful in ensuring seasonal reductions, states must remain below daily peak levels, not just seasonal levels, to reach attainment. These downwind stakeholder communities have suggested that operating pollution controls on the highest ozone days (and immediately preceding days) during the ozone season is of critical importance. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and has identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. These instances are discussed in section V.B.1.a of this document and in the EGU NO_X Mitigation Strategies Final Rule TSD in the docket. While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-optimization to take the step of building in enhancements to the trading program to ensure unit-level control operation, our review of subsequent-year data for prior programs suggests that the non-optimization

[296] *E.g.,* comments of Maryland Department of the Environment on the proposed Revised CSAPR Update at 3, EPA–HQ–OAR–2020–0272–0094.

behavior increases in the latter years of a program. Applied to this context (*e.g.,* a rule providing a full remedy to interstate transport for the more protective 2015 ozone NAAQS and an extended period of expected persistence of receptors), this data suggests this deterioration in performance could become prevalent and problematic in future years if not addressed. Rather than allow for the potential of continued deterioration in the environmental performance of our trading programs, the EPA finds the evidence of declining SCR performance in later years of trading programs sufficient to justify prophylactic measures in this rule to ensure the emissions control strategy selected at Step 3 is indeed implemented at Step 4. Thus, particularly in the context of the more protective 2015 ozone NAAQS combined with the full remedy nature of this action and the extended timeframe for which upwind contribution to downwind nonattainment is projected to persist, the EPA agrees with these stakeholders that the set of measures promulgated in this rulemaking to implement the control stringency levels found necessary to address states' good neighbor obligations should include measures designed to more effectively ensure that individual units operate their emissions controls routinely throughout the ozone season, thereby also ensuring that the controls are planned to be in operation on the particular days that turn out to be most critical for ozone formation and for attainment of the NAAQS. Routine operation of emissions controls will also provide relief to overburdened communities downwind of any units that might otherwise have chosen not to operate their controls. In the Ozone Transport Policy Analysis Final Rule TSD, the EPA conducted a screening analysis that found nearly all of the EGUs included in this analysis are located within a 24-hour transport distance of many areas with potential EJ concerns. Thus, the EPA is adopting backstop daily rate limits at the individual unit level because it is appropriate and justified in the context of eliminating significant contribution under CAA section 110(a)(2)(D)(i)(I). While the former justification is sufficient to finalize this enhancement to the trading program, we also anticipate that this measure will deliver public health and environmental benefits to overburdened communities (as well as the rest of the population).[297]

We considered whether, as some commenters suggested, it would be appropriate to simply implement unit-specific daily emissions limitation at all of the large, coal-fired EGUs, and forego an emissions trading approach altogether. While this is within the EPA's statutory authority, *see* CAA section 110(a)(2)(A) and 302(y), and merits careful consideration, we are declining to do so in this action but intend to closely monitor EGU emissions performance in response to the trading program finalized here. The purpose of establishing a backstop daily NO_X emissions rate and implementing it through additional allowance surrender requirements instead of as an enforceable emissions limitation is to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. As discussed in section VI.B.7 of this document, under the EPA's historical trading programs without the enhancements made in this rulemaking, some individual coal-fired units with SCR controls have chosen to operate the controls at lower removal efficiencies than in past ozone seasons or even to idle the controls for entire ozone seasons. In addition, some SCR-equipped units have chosen to routinely cycle their emissions controls off at lower load levels, such as while operating overnight, instead of operating the controls, upgrading the units to enable the controls to be operated under those conditions, or not operating the units under those conditions. Collectively, this non-optimization of existing controls has a detrimental impact on problematic receptors. Table V.D.1–1 shows the expected air quality benefit from control optimization (totaling nearly 1.6 ppb change across all receptors).[298]

The EPA has identified sources of interstate ozone pollution such as the New Madrid and Conemaugh plants (in Missouri and Pennsylvania, respectively) whose SCR controls were not operating for substantial portions of recent ozone seasons. The data included in Appendix G of the Ozone Transport Policy Analysis Final Rule TSD, available in the docket for this rulemaking, demonstrate that these units have operated their SCRs better and more consistently during years with higher NO_X allowance prices. Downwind stakeholders have noted that some of the higher emissions rates (specifically in the case of Conemaugh Unit 2 in 2019) have occurred on the day of and the preceding day of an ozone exceedance in bordering states.[299]

The EPA believes that the design of the daily emissions rate provisions will be effective in addressing these types of high-emitting behavior by significantly raising the cost of planned operator decisions that substantially compromise environmental performance. At the same time, the provision will not unduly penalize an occasional unplanned exceedance, because the amount of additional allowances that would have to be surrendered to address a single day's exceedance would be much smaller than the amount that would have to be surrendered to address planned poor performance sustained over longer time periods. Moreover, the EPA believes that the inclusion of a 50-ton threshold before the increased surrender requirements would apply is sufficient to address virtually all instances where a unit's emissions would exceed the 0.14 lb/mmBtu daily rate because of unavoidable startup or shutdown conditions during which SCR equipment cannot be operated, thereby ensuring that the provision will not penalize units for emissions that are beyond their reasonable control.

The EPA is applying the daily emissions rate provisions to large coal-fired EGUs, and not to other types of units, for reasons that are consistent with EPA's determinations regarding the appropriate control stringency for EGUs to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. Installation and operation of SCR controls is well-established as a common practice for the best control of NO_X emissions from coal-fired EGUs, as evidenced by the fact that the technology is already installed on more than 60 percent of the sector's total coal-fired capacity and installed on nearly 100 percent of the coal fired boilers in the top quartile of emissions rate performance. In the context of addressing good neighbor obligations with respect to the 2015 ozone NAAQS, the EPA is determining that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs (other than circulating fluidized bed units) is appropriate at Step 3. Finally, where SCR controls are installed on such units, optimized operation of those controls is an extremely cost-effective method of achieving NO_X emissions

[297] Nonetheless, the environmental justice exposure analysis indicates that preexisting disparities among demographic groups are likely to persist even under this final rule. *See* section VII of this document.

[298] As illustrated in the table and underlying data, a small portion of this ppb impact is attributable to combustion control upgrade potential.

[299] EPA–HQ–OAR–2020–0272–0094.

reductions. The EPA believes these considerations support establishment of the daily emissions rate provisions on a universal basis for large coal-fired EGUs, with near-term application of the provisions for units that already have the controls installed and deferred application for other units, as discussed later.

With regard to gas-fired steam EGUs, SCR controls are nowhere near as prevalent, and while the EPA is including some SCR controls at gas-fired steam units in the selected control stringency at Step 3, the EPA is not including universal SCR controls at gas-fired steam units. Because the EPA is not determining that universal installation and operation of SCR controls at gas-fired steam EGUs is part of the selected control stringency, in order not to constrain the power sector's flexibility to choose which particular gas-fired steam EGUs are the preferred candidates for achieving the required emissions reductions, the EPA is not applying the daily emissions rate provisions to large gas-fired steam EGUs. Focusing the backstop daily emissions rates on coal-fired units is also consistent with stakeholder input which has emphasized the need for short-term rate limits at coal units given their relatively higher emissions rates.

The EPA developed the level of the daily average NO_X emissions rate—0.14 lb/mmBtu—through analysis of historical data, as described in section VI.B.7 of this document. A rate of 0.14 lb/mmBtu represents the daily average NO_X emissions rate that has been demonstrated to be achievable on approximately 95 percent of days covering more than 99 percent of total ozone-season NO_X emissions by coal-fired units with SCR controls that are achieving a seasonal NO_X average emissions rate of 0.08 lb/mmBtu (or less), which is the seasonal NO_X emissions rate that the EPA has determined is indicative of optimized SCR performance by units with existing SCR controls.

As noted previously, the daily average emissions rate provisions will apply beginning in the 2024 control period for large coal-fired units with installed SCR controls, one control period later than optimization of those controls will be reflected in the state emissions budgets under this rule. For these units, not applying the daily average rate provisions until 2024 serves three purposes. First, it provides all the units with a preparatory interval to focus attention on improving not only the average performance of their SCR controls but also the day-to-day consistency of performance before they will be held to increased allowance-surrender consequences for exceeding the daily rate. Second, it provides the subset of units that exhaust to common stacks with other units that currently lack SCR controls an opportunity to exercise the option to install and certify any additional monitoring systems needed to monitor the individual units' NO_X emissions rates separately; otherwise, the daily emissions rate provisions will apply to the SCR-equipped units based on the combined NO_X emissions rates measured in the common stacks. Third, it provides all units sufficient time to update the data handling software in their existing monitoring systems as needed to compute and report the additional hourly and daily data values needed for implementation of the provisions.[300]

With respect to the units without existing SCR controls, the daily average emissions rate provisions will apply starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. This implementation timing represents a change from the proposal, under which the daily average emissions rate provisions would have applied to units without existing SCR starting in the 2027 control period. Commenters noted that for many units without SCR, replacement of the unit within a few years, and shifting of some generation to cleaner units in the interim, would be a more economic compliance strategy than installation of new SCR controls. The commenters further noted that implementation of the daily average emissions rate for these units starting in 2027 would strongly disadvantage such an alternative strategy if the capacity replacement and any associated transmission improvements could not be implemented by 2027. In light of these comments, the EPA has determined that as long as the emissions budgets determined in this rule to eliminate significant contribution are still being implemented as expeditiously as practicable—which in this instance the EPA has determined requires phasing in the required emissions reductions by 2027—it is reasonable to defer implementation of the daily average emissions rate provisions to 2030 for units without SCR to allow temporarily greater flexibility to pursue compliance strategies other than installation of new controls. This lag is permissible consistent with the obligation to eliminate significant contribution for reasons that are further discussed in response to comments in section VI.B.1.d of this document. However, for any units that choose a compliance strategy of installing new SCR controls before 2030, the daily average emissions rate provisions would apply in the second control period of operation. Specification of the second control period rather than the first control period provides the unit operators with an opportunity to gain operational experience with the new equipment before the units will be held to increased allowance-surrender consequences for exceeding the daily rate.

The unit-specific daily emissions rate provisions are being finalized as proposed except for two changes noted in the previous summary: the exclusion from extra allowance surrender requirements of a unit's first 50 tons of emissions in a control period exceeding the backstop daily rate, and the revision of the starting date for implementation of the requirement for units without existing SCR controls to 2030 or the second control period of SCR operation, if earlier. The rationale for these changes is further discussed in the responses to comments later in this section. Additional details of the unit-specific daily emissions rate provisions are discussed in section VI.B.7 of this document.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the trading program enhancements intended to improve emissions performance at the level of individual units is the addition of unit-specific secondary emissions limitations for units with post-combustion controls starting with the 2024 control period. The secondary emissions limitations will be determined on a unit-specific basis according to each unit's individual performance but will apply to a given unit only under the circumstance where a state's assurance level for a control period has been exceeded, the unit is included in a group of units to which responsibility for the exceedance has been apportioned under the program's assurance provisions, and the unit operated during at least 10 percent of the hours in the control period. Where these conditions for application of a secondary emissions limitation to a given unit for a given control period are met, the unit's secondary emissions limitation consists of a prohibition on NO_X emissions during the control

[300] For further discussion of emissions monitoring and reporting requirements under the rule, including the options available to plants where SCR-equipped and non-SCR-equipped coal-fired units exhaust to common stacks, see section VI.B.10 of this document.

period that exceed by more than 50 tons the NO_X emissions that would have resulted if the unit had achieved an average emissions rate for the control period equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest average emissions rate for any previous control period under any CSAPR seasonal NO_X trading program during which the unit operated for at least 10 percent of the hours.

The secondary emissions limitation is in addition to, not in lieu of, the primary emissions limitation applicable to each source, which continues to take the form of a requirement to surrender a quantity of allowances based on the source's emissions, and also in addition to the existing assurance provisions, which similarly continue to take the form of a requirement for the owners and operators of some sources to surrender additional allowances when a state's assurance level is exceeded. In contrast to these other requirements, the unit-specific secondary emissions limitation takes the form of a prohibition on emissions over a specified level, such that any emissions by a unit exceeding its secondary emissions limitation would be subject to potential administrative or judicial action and subject to penalties and other forms of relief under the CAA's enforcement authorities. The reason for establishing this form of limitation is that experience under the existing CSAPR trading programs has shown that, in some circumstances, the existing assurance provisions have been insufficient to prevent exceedances of a state's assurance level for a control period even when the likelihood of an exceedance has been foreseeable and the exceedance could have been readily avoided if certain units had operated with emissions rates closer to the lower emissions rates achieved in past control periods. The assurance levels exist to ensure that emissions from each state that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state are prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). The EPA's programs to eliminate significant contribution must therefore achieve this prohibition, and the evidence of foreseeable and avoidable exceedances of the assurance levels demonstrates that EPA's existing approach has not been sufficient to accomplish this.

The purpose of including assurance levels higher than the state emissions budgets in the CSAPR trading programs is to provide flexibility to accommodate operational variability attributable to factors that are largely outside of an individual owner's or operator's control, not to allow owners and operators to plan to emit at emissions rates that could be anticipated to cause a state's total emissions to exceed the state's emissions budget or assurance level. Conduct leading to a foreseeable, readily avoidable exceedance of a state's assurance level cannot be reconciled with the statutory mandate of the CAA's good neighbor provision that emissions "within the state" significantly contributing to nonattainment or interfering with maintenance of a NAAQS in another state must be prohibited. Because the current CSAPR regulations do not expressly prohibit such conduct and have proven insufficient to deter it in some circumstances, the EPA is correcting the regulatory deficiency in the Group 3 trading program by adding secondary emissions limitations that cannot be complied with through the use of allowances.

The EPA notes that although the purpose of the secondary emissions limitations is to strengthen the assurance provisions, which apply on a statewide, seasonal basis, the unit-specific structure of the new limitations will strengthen the incentives for individual units with post-combustion controls to maintain their emissions performance at levels consistent with their previously demonstrated capabilities. The new limitations will strengthen the incentives to operate and optimize the controls continuously, which can be expected to reduce some individual units' emissions rates throughout the ozone season, including on the days that turn out to be most critical for downwind ozone levels. Better emissions performance on average across the ozone season by individual units likely will also help address impacts of pollution on overburdened communities downwind from some such units. *See* Ozone Transport Policy Analysis Final Rule TSD, Section E.

The unit-specific secondary emissions limitations are being finalized as proposed except that the limitations will apply only to units with post-combustion controls. The rationale for this change, and additional details regarding the provisions, are discussed in section VI.B.8 of this document.

d. Responses to General Comments on the Revisions to the Group 3 Trading Program

This section summarizes and provides the EPA's responses to overarching comments received on the EPA's proposal to implement the emissions reductions required from EGUs under this rule through expansion and enhancement of the Group 3 trading program originally established in the Revised CSAPR Update, particularly comments on electric system reliability. Responses to comments about individual aspects of the enhanced trading program are addressed in the respective subsections of this section in which those aspects are discussed. Responses to comments concerning alleged overcontrol and the EPA's legal authority are in sections V.D. and III. Comments not addressed in this document are addressed in the separate *RTC* document available in the docket for this action.

Comment: Some commenters, including EGU owners, states, and several RTOs, expressed concern that the requirements for EGUs as formulated in the proposal could lead to a degradation in the reliability of the electric system. As background, some of these commenters noted that the power sector is currently undergoing rapid change, with older and less economic fossil-fuel-fired steam generating units retiring while the majority of the new capacity being added consists of wind and solar capacity. They noted that fossil-fuel-fired generating capacity provides reliability benefits not necessarily provided by other types of generating capacity, including not only the ability to generate electricity in the absence of wind or sunlight, but also inertia, ramping capability, voltage support, and frequency response. Commenters stated that past EGU retirements and the pace of change in the generating capacity mix have already been stressing the electric system in some regions, and that the forecasted risk of events where the electric system would be unable to fully meet load is rising.

For purposes of their comments, these commenters generally assumed that the rule would lead to additional retirements of fossil-fuel-fired generating capacity beyond the retirements that EGU owners have already planned and announced. Some of the commenters also suggested that remaining fossil-fuel-fired generators would be unwilling to operate when needed because allowances might be unavailable for purchase or too costly. In the context of an already-stressed electric system, the commenters predicted that these assumed consequences of the rule would threaten resource adequacy and result in degraded electric reliability. To support their assumptions concerning additional retirements, some of the commenters pointed to projections of incremental generating capacity retirements included in the results of modeling performed by the EPA to analyze the costs and benefits of the proposed rule. Some commenters indicated that they expected EGU owners to be interested in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and expressed concern that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy; for these commenters, 2027 and the immediately following years were the period of greatest concern. Some commenters appear simply to have assumed that owners of units not already equipped with SCR controls would choose to retire the units as of the ozone season in which the units would otherwise become subject to the backstop daily emissions rate provisions, regardless of whether replacement investments had been completed.

Some of the commenters raising concerns about electric system reliability suggested potential modifications to the proposed rule that the commenters believed could help address their concerns. The suggestions included various mechanisms for suspending some or all of the trading program's requirements for certain EGUs at times when an RTO or other entity responsible for overseeing a region of the interconnected electrical grid determines that generation from those EGUs is needed and the EGUs might not otherwise agree to operate. Other suggestions focused on ways of providing EGUs with greater confidence that allowances would be available to cover their incremental emissions during particular events. A number of commenters used the term ''reliability safety valve,'' in some cases with reference to the types of suggestions just mentioned and in other cases without details. Some commenters pointed to the ''safety valve'' provision included in the Group 2 trading program regulations under the Revised CSAPR Update. Another commenter pointed to provisions for a ''reliability safety valve'' included in the Clean Power Plan (80 FR 64662, Oct. 23, 2015).

In addition to offering critiques and recommendations concerning the proposed rule's contents, some commenters claimed that the EPA had failed to conduct sufficient analysis of the potential implications of the proposed rule on electrical system reliability. These commenters called on the EPA to consult with RTOs and other entities with responsibilities relating to electric system reliability and to perform additional analysis. Some commenters advocated for renewed consultations and analysis before each planned adjustment to emissions budgets under the dynamic budget-setting process. Commenters cited the consultation processes followed during implementation of other EPA rules, such as the Mercury and Air Toxics Standards (MATS) (77 FR 9304, Feb. 16, 2012).

Response: The EPA disagrees with the comments asserting that this rule would threaten resource adequacy or otherwise degrade electric system reliability. The emissions reduction requirements for EGUs under this rule are being implemented through the mechanism of an allowance trading program. Under the trading program, no EGU is required to cease operation. The core trading program requirements for a participating EGU are to monitor and report the unit's NO_X emissions for each ozone season period and to surrender a quantity of allowances after the end of the ozone season based on the reported emissions. To address states' obligations under the good neighbor provision, some units of course will have to take some type of action to reduce emissions, the actions taken to reduce emissions will generally have costs, and some EGU owners will conclude that, all else being equal, retiring a particular EGU and replacing it with cleaner generating capacity is likely to be a more economic option from the perspective of the unit's customers and/or owners than making substantial investments in new emissions controls at the unit. However, the EPA also understands that before implementing such a retirement decision, the unit's owner will follow the processes put in place by the relevant RTO, balancing authority, or state regulator to protect electric system reliability. These processes typically include analysis of the potential impacts of the proposed EGU retirement on electrical system reliability, identification of options for mitigating any identified adverse impacts, and, in some cases, temporary provision of additional revenues to support the EGU's continued operation until longer-term mitigation measures can be put in place. No commenter stated that this rule would somehow authorize any EGU owner to unilaterally retire a unit without following these processes, yet some comments nevertheless assume that is how multiple EGU owners would proceed, in violation of their obligations to RTOs, balancing authorities, or state regulators relating to the provision of reliable electric service. Assumptions of this nature are simply not reasonable. Like many commenters, the EPA does expect that retirement will be viewed as a more economic compliance strategy for some EGUs than installing new controls, but the Agency also expects that any resulting unit retirements will be carried out through an orderly process in which RTOs, balancing authorities, and state regulators use their powers to ensure that electric system reliability is protected. The trading program inherently provides ample flexibility to allow such an orderly transition to take place. In addition, as discussed later in this section, the EPA has adopted several changes in the final rule to increase flexibility specifically for the early years of the trading program for which commenters have indicated the greatest concerns about electric system reliability.

As an initial matter, the EPA notes two fundamental aspects of this rulemaking which together provide a strong foundation for the Agency's conclusion that the emissions reductions required from EGUs can be achieved with no adverse impacts on electric system reliability. First, there is ample evidence indicating that the required emissions reductions are feasible. As discussed in section V of this document, the magnitude and timing of the EGU emissions reductions required by this action reflect application of technologies that are already in widespread use, on schedules that are supported by industry experience. Second, the required emissions reductions are being implemented through the mechanism of a trading program. The enhanced trading program under this rule, like the trading programs established by the EPA under prior rules, provides EGU owners with opportunities to substitute emissions reductions from sources where achieving reductions is cheaper and easier for emissions reductions from other sources where achieving reductions is more costly or difficult. In general, an EGU owner has options to operate the emissions controls identified by the EPA for that type of unit (including installation or upgrade of controls where necessary), operate other types of emissions controls, or adapt the unit's levels of operation to produce less generation if the unit is a higher-emitting EGU or more generation if the unit is a lower-emitting EGU. The backstop daily emissions rate provisions in this rule reduce the degree of available flexibility relative to the degree of flexibility in the Agency's previous trading programs under CAIR and CSAPR but by no means eliminate it. Moreover, even the backstop rate provisions are structured as requirements to surrender additional allowances rather than as hard limits, providing a further element of flexibility No EGU is required to retire or is prohibited from operating at any time under this rule. EGUs only need to surrender of the appropriate quantities of allowances after the end of the control period.[301]

Further, in the large number of comments submitted in this rulemaking that assert concerns over electric system reliability, no commenter has cited a single instance where implementation of an EPA trading program has actually caused an adverse reliability impact. Indeed, similar claims made in the context of the EPA's prior trading program rulemakings have shown a considerable gap between rhetoric and reality. For example, in the litigation over the industry's multiple motions to stay implementation of CSAPR, claims were made that allowing the rule to go into effect would compromise reliability. Yet in the 2012 ozone season starting just over 4 months after the rule was stayed, EGUs covered by CSAPR collectively emitted below the overall program budgets that the rule would have imposed in that year if the rule had been allowed to take effect, with most individual states emitting below their respective state budgets despite CSAPR not being in effect.[302] Similarly, in the litigation over the 2015 Clean Power Plan, assertions that the rule would threaten electric system reliability were made by some utilities or their representatives, yet even though the Supreme Court stayed the rule in 2016, the industry achieved the rule's emissions reduction targets without the rule ever going into effect. *See West Virginia* v. *EPA,* 142 S. Ct. 2587, 2638 (2022) (Kagan, J., dissenting) (''[T]he industry didn't fall short of the [Clean Power] Plan's goal; rather, the industry exceeded that target, all on its own. . . . At the time of the repeal . . . 'there [was] likely to be no difference between a world where the [Clean Power Plan was] implemented and one where it [was] not.' '') (quoting 84 FR 32561). The claims that these rules would have had adverse reliability impacts were proved to be groundless.

Notwithstanding the long experience confirming the ability of the EPA's trading programs to obtain emissions reductions from EGUs without impairing the sector's ability to provide reliable electric service, the Agency of course does not rely here solely on its experience, but has carefully reviewed the comments on this topic for any information that might indicate the appropriateness of modifications to the enhanced trading program as proposed. In recognition of the important role that RTOs play in ensuring electric system reliability, and consistent with the requests of some commenters, the EPA has engaged in outreach to the RTOs that commented on the proposal to better understand their comments specifically and the reliability-related comments of other commenters more generally.[303] Through these meetings, the central reliability-related concern was identified as one of timing. In order for retirement to be a viable compliance strategy for a unit that cannot be entirely spared until replacement investments in generation or transmission are completed, it must be possible for the unit to operate at critical times for a transition period. Like other stakeholders, the RTOs perceived implementation of the backstop daily emissions rate provisions on uncontrolled units as materially strengthening incentives for such units to either install controls or retire. The RTOs were concerned that the option for a coal-fired unit without SCR controls to maintain limited operation while surrendering allowances at a 3-for-1 ratio for all emissions exceeding the backstop daily rate was one that EGU owners would be reluctant to pursue. Accordingly, the RTOs expected considerable interest from EGU owners in retiring and replacing uncontrolled units as of the date of implementation of the backstop daily rate requirement on uncontrolled units, and they were concerned that the proposal to implement that requirement as of the 2027 control period did not allow sufficient time for planning and implementation of all the necessary generation and transmission investments to make this a viable compliance strategy. The RTOs described their concerns as greatest through approximately the 2029 control period.

The RTOs also described a concern about potentially illiquid allowance markets. They believed it was possible that some EGUs might claim an inability to operate at particular times when needed unless they had confidence that they would be able obtain additional allowances. The RTOs were particularly concerned that introduction of dynamic budgeting as proposed would create uncertainty for some EGUs regarding the quantities of allowances they would have available for use, particularly given the potentially large year-to-year swings if budgets were based on historical data from a single year. Some of the RTOs suggested potential solutions for these issues, principally in the form of auctions or RTO-administered allocations of allowances from pools of supplemental allowances, with access to the supplemental allowances triggered by certain indications of temporary stress on the electric system.

In the final rule, the EPA is adopting several changes from the proposal to help address the reliability-related concerns that were identified in comments and brought into greater focus by the consultations with the RTOs. The first change adopted in response to these comments is that application of the backstop daily NO_X emissions rate to units without existing SCR controls is being deferred until the 2030 control period, or the second control period in which a unit operates new SCR controls, if earlier. The purpose of this change is to address the concerns that application of the backstop daily NO_X emissions rate to EGUs without existing SCR starting in 2027 would provide insufficient time for planning and investments needed to facilitate unit retirement as a compliance pathway, which some commenters noted they prefer or have already planned. In particular, where an EGU owner would prefer to retire and replace an uncontrolled EGU rather than to install new controls, and in recognition that reliability-related needs may require some degree of operation from such units in the period before the investments needed to replace the unit can be completed, deferral of the backstop daily emissions rate provisions ensures that the necessary generation can be provided without being made subject to a 3-for-1 allowance surrender ratio that might render that compliance strategy uneconomic compared to the faster but less environmentally beneficial compliance strategy of installing new controls. The EPA has considered the statutory mandate that states' good neighbor obligations—

[301] The EPA has prepared a resource adequacy assessment of the projected impacts of the final rule showing that the projected impacts of the final rule on power system operations, under conditions preserving resource adequacy, are modest and manageable. See *Resource Adequacy and Reliability Analysis Final Rule TSD,* available in the docket.

[302] For a state-by-state comparison, see Appendix G of the Ozone Transport Policy Analysis Final Rule TSD.

[303] The EPA also met with non-RTO balancing authorities that submitted comments. Memoranda identifying the dates, attendees, and topics of discussion of these meetings with RTOs and non-RTO balancing authorities are available in the docket.

including this action's requirement for large coal-fired EGUs to make emissions reductions commensurate with good SCR operation—be addressed as expeditiously as practicable. The EPA has also considered the fact that in this rule, the backstop daily emissions rate serves as a supplement to the broader requirement for emissions reductions commensurate with application of several control technologies at several types of EGUs, encompassing the extent of emissions reductions that would be incentivized by the backstop emissions rate requirement. The EPA views the backstop daily emissions rate as part of the solution to eliminating significant contribution in that it strongly incentivizes emissions-control operation throughout each day of the ozone season. *See* sections III.B.1.d, VI.B.1.b, VI.B.1.c.i. For that reason, in general we are finalizing the daily backstop emissions rate for units that have SCR installed or that install it in the future. It is only as an exception to that general rule that we defer the backstop daily emissions rate given the transition period and reliability concerns identified by commenters. The EPA finds that in this circumstance, as long as state emissions budgets continue to reflect the required degree of emissions reductions, deferral of the backstop rate requirement for uncontrolled units for a transition period can be justified on the basis of the greater long-term environmental benefits obtained through facilitating the replacement of these affected EGUs with cleaner sources of generation. Beginning in the 2030 ozone season, all coal-fired EGUs identified for SCR retrofit potential in this action will be subject to the backstop daily emissions rate. Any such units that remain in operation in that year can and should meet the backstop daily emissions rate or be subject to the heightened allowance surrender ratio.

The second change from the proposal adopted in response to the reliability-related comments is that the target percentage of the states' emissions budgets used to recalibrate the target bank level will be set at the proposed 10.5 percent starting in the 2030 control period, and for the control periods from 2024 through 2029, a target percentage of 21 percent will be used instead. The adoption of the higher target percentage for use through the 2029 control period is intended to promote greater allowance market liquidity during a period of relatively rapid fleet transition about which commenters expressed more focused reliability-related needs. As discussed later in this section, the EPA expects the introduction of the bank recalibration process in 2024 generally to boost market liquidity (by discouraging allowance hoarding) and also considers the target percentage of 10.5 percent set forth in the proposal well supported. Nevertheless, the Agency agrees with suggestions by commenters that, at least in the early years of the enhanced trading program, a larger bank would provide further liquidity and would give program participants greater confidence that allowances would be available for purchase when needed. Greater confidence by sources would help address RTOs' concern about the possibility that some sources could be reluctant to operate if they were unsure of their ability to procure allowances to cover their emissions. In finding that this modification from proposal is appropriate, the EPA has considered the fact that use of a higher target percentage will not result in the creation of any additional allowances in any control period, because under the recalibration provisions, when the total quantity of allowances banked from the previous control period is less than the bank target level, the consequence is not that additional allowances are created to raise the bank to the target level, but simply that no bank adjustment is carried out. We also note that while including an annual bank recalibration of any percentage is an enhancement in the trading program from prior trading programs under the good neighbor provision established in the CAIR, CSAPR, CSAPR Update, and Revised CSAPR Update rulemakings, it is not unprecedented; the trading program established under the NO_X SIP Call included ''progressive flow control'' provisions that were designed differently from the bank recalibration provisions in this rule but had the same purpose and general effect.

The third change from the proposal adopted in response to the reliability-related comments is that the EPA is determining preset state emissions budgets not only for the control periods in 2023 and 2024 as proposed, but also for the control periods in 2025 through 2029. Finalizing preset state emissions budgets through 2029 will establish predictable amounts for the minimum quantities of allowances available during the period when commenters have expressed concern that the reliability-related need for such predictability is greatest. Moreover, the EPA will also determine state emissions budgets using the final dynamic budget-setting methodology for the control periods in 2026 through 2029, and for each state and control period, the dynamic budget to be published in the future will only supplant the preset budget finalized in this rule for a control period in which that dynamic budget is higher than the corresponding preset budget. The reason for using dynamic budgets when they are higher than the corresponding preset budgets is that the EPA recognizes that evolution of the EGU fleet will not follow the exact path projected at the time of the rulemaking, and that by not accounting for certain events, the preset methodology could result in issuance of smaller quantities of allowances than the EPA would find consistent with the quantities of emissions from a well-controlled EGU fleet using the dynamic budget-setting methodology. Events that could cause preset budgets to underpredict a state's well-controlled emissions, which are more likely in years farther in the future from the time of the rulemaking, include deferral of a large EGU's previously planned retirement date or increases in electricity demand that outpace the general trend of lower-emitting or non-emitting generation replacing higher-emitting generation. After considering the commenters' interest in greater predictability during the early years of the amended trading program as well as the need to protect against instances where the preset budgets could underpredict a state's well-controlled emissions in years farther from the year of the rulemaking, the EPA finds that the combination of these factors justifies the approach of using the higher of the two budgets for the control periods from 2026 through 2029.

In addition to the changes made in response to reliability-related comments, several other changes to the proposal being adopted primarily for other reasons will also help address the factors identified as reliability-related concerns. Most notably, the EPA is adopting changes to the dynamic budget computation procedure to incorporate multiple years of heat input data, which will reduce year-to-year variability in the budgets determined under that procedure and should to some extent reduce uncertainty about the quantities of allowances available for use in instances where a dynamic budget is being used instead of preset budget. In addition, the adoption of a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate should ensure that no unit incurs the higher surrender ratio solely because of unavoidable emissions during startup and should help address concerns that some units might be reluctant to operate because of the associated emissions-related costs. Also, the 2026–2027 phase-in of emissions reductions commensurate with installation of new SCR controls will increase the quantities of allowances available in the 2026 state emissions budgets for most states in the trading program.

To summarize: in light of the strong record supporting the feasibility of the emissions reductions required from EGUs; the use of a trading program as the mechanism for achieving those emissions reductions, with multiple options for achieving compliance and no requirements to cease operation of any individual EGU at any time; the established processes of RTOs, other balancing authorities, and state regulators for managing any EGU retirement requests that do occur in an orderly manner with evaluation of potential reliability impacts and implementation of mitigation measures where needed; the unbroken, decades-long historical success of the EPA's trading programs at achieving emissions reductions without any adverse reliability impacts; the views expressed by commenters that facilitating EGU retirement and replacement as a possible compliance strategy through 2029 would be particularly helpful; the changes made in the final rule for control periods through 2029 specifically to increase flexibility during this transitional period, including deferring application of the backstop daily emissions rate provisions for EGUs without existing SCR controls, increasing the target percentage used to determine the target allowance bank level for purposes of the bank recalibration provisions, and establishing preset state emissions budgets which serve as floors against potential dynamic budget imposition in those control periods; and the changes made in the final rule incorporating multiple years of heat input data into the dynamic budget-setting procedure, adding a 50-ton threshold before application of the 3-for-1 surrender ratio to emissions exceeding the backstop daily NO_X emissions rate, and phasing in emissions reductions requirements commensurate with new SCR installations through 2027; the EPA concludes that this action does not pose any material risk of adverse impact to electric system reliability.

The EPA has also considered the other suggestions offered by commenters for addressing reliability-related issues. With respect to suggestions that the rule should include provisions allowing some or all of the trading program's requirements to be suspended at times when an RTO or other entity with grid management responsibilities determines there is a reliability-related need, the EPA again observes that the rule's emissions reduction requirements are being implemented through a trading program mechanism which makes exceptions of this nature unnecessary. Trading programs inherently offer the flexibility to accommodate variability in the utilization of individual units. The ''reliability safety valve'' provisions in the Clean Power Plan, which one commenter cited as a precedent to support some form of temporary exemption under this rule, in fact was available only in situations where a state plan did not allow emissions trading and instead imposed unit-specific emissions constraints. *See* 80 FR 64877–879. Even the 3-for-1 allowance surrender ratio under the backstop daily NO_X emissions rate provisions can be met through the surrender of additional allowances. The rule does not bar any EGU from operating at any time as long as all allowance surrender requirements are met.

With respect to suggestions that the EPA must undertake recurring modeling of the evolving electrical system and consult with RTOs before each planned adjustment to emissions budgets, which start from the premise that the rule poses risk to electric system reliability that must be continuously monitored, the EPA disagrees with the premise and therefore also disagrees with the suggestions. As discussed in section V of this document, the EPA has taken care to ensure that the emissions reduction requirements applicable to EGUs under this rule are feasible through application of the control technologies selected as the basis of the emissions reductions. The EPA has also performed modeling in this rulemaking to assess the benefits and costs of the rule when all required emissions reductions are achieved. That modeling, which incorporates a representation of electrical grid regions and interregional constraints on energy and capacity exchange, affirms the feasibility of the overall emissions reduction requirements and is illustrative of a control strategy where some units retire and are replaced instead of installing new controls. The EPA has also consulted with the RTOs (as well as other balancing authorities) in the course of this rulemaking to ensure that the EPA understood the concerns expressed in their comments such that we could address those comments in this final rule. The EPA does not agree that further modeling or ongoing consultations with RTOs are needed in advance of the recurring dynamic budget adjustments, which do not increase the stringency of the rule's emissions reduction requirements established in the final rule. The extensive consultation processes adopted by the Agency in conjunction with the MATS rulemaking are not a relevant precedent; the MATS rule, which was promulgated to address a different statutory mandate, was structured in the form of unit-specific emissions constraints, fundamentally different from the requirements of this rule. The EPA notes that other entities responsible for maintaining reliability and managing entry and exit of resources, including the North American Electric Reliability Corporation (NERC) and RTOs and other balancing authorities, already routinely assess resource adequacy and reliability inclusive of meeting all regulatory requirements, including environmental requirements.

While the EPA does not agree that such consultations are a necessary precondition for successful implementation of this rule, the Agency remains available to engage with any affected EGU or reliability authority requesting to meet and discuss the intersection of its power sector regulatory programs with electric reliability planning and operations. The EPA is also continuing its practice of meeting with the U.S. Department of Energy and the Federal Energy Regulatory Commission to maintain mutual awareness of how Federal actions and programs intersect with the industry's responsibility to maintain electric reliability.[304]

The EPA is not adopting the suggestion to replicate the so-called ''safety valve'' mechanism created under the Revised CSAPR Update. That mechanism, cited by some commenters as potential precedent for an unspecified form of ''reliability safety valve'' in this action, gave owners of covered EGUs a one-time opportunity to voluntarily convert allowances banked under the Group 2 trading program to allowances useable in the Group 3 trading program at an 18-for-1 ratio for use in the trading program's initial control period in 2021. *See* 82 FR 23137–138. EGU owners chose to use the voluntary mechanism to acquire a total of 382 allowances, representing only 0.36 percent of the sum of the state emissions budgets and only 0.26 percent

[304] *See, e.g.,* U.S. Department of Energy and U.S. Environmental Protection Agency, Joint Memorandum on Interagency Communication and Consultation on Electric Reliability (March 8, 2023), available at *https://www.epa.gov/power-sector/electric-reliability-mou.*

of the total quantity of allowances available for compliance in that control period.[305] For the 2023 control period, the bank of allowances carried over from the 2022 control period plus the incremental starting bank that will be created by conversion of additional allowances banked under the Group 2 trading program (see section VI.B.12.b of this document) will total over 30 percent of the full-season emissions budgets.[306] Given the larger starting bank and this rule's bank recalibration provisions (which will be implemented starting with the 2024 control period, but which the EPA expects will increase allowance market liquidity starting with the 2023 control period), the Agency views establishment of a one-time voluntary conversion opportunity for the 2023 control period analogous to the Revised CSAPR Update's ''safety valve'' provision as unnecessary.

Finally, in the final rule the EPA is not adopting any of the other suggestions concerning additional mechanisms to make additional allowances available through auctions or RTO-administered allowance pools. For the reasons discussed throughout this section, the EPA concludes that the trading program as established in this action provides a flexible compliance mechanism that will allow the required emissions reductions to be achieved without the need for creation of additional allowances. However, the EPA also recognizes the potential for allowance market liquidity to be further increased through some form of auction mechanism. For instance, it may be appropriate to pair the introduction of an auction with a reduction in the bank recalibration percentage that begins earlier than 2030. Through a supplemental rulemaking, the Agency intends to propose and take comment on potential amendments to the Group 3 trading program that would add such an auction mechanism to the regulations and make other appropriate adjustments in the implementation framework at Step 4.[307]

2. Expansion of Geographic Scope

In light of the findings at Steps 1, 2, and 3 of the 4-step interstate transport framework, the EPA is expanding the geographic scope of the existing CSAPR NO_X Ozone Season Group 3 Trading Program to encompass additional states (and Indian country within the borders of such states) with EGU emissions that significantly contribute for purposes of the 2015 ozone NAAQS. Specifically, the EPA is expanding the Group 3 trading program to include the following states and Indian country within the borders of the states: Alabama, Arkansas, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, Utah, and Wisconsin. Any unit located in a newly added jurisdiction that meets the applicability criteria for the Group 3 trading program will become an affected unit under the program, as discussed in section VI.B.3 of this document.

CSAPR, the CSAPR Update, and the Revised CSAPR Update also applied to sources in Indian country, although, when those rules were issued, no existing EGUs within the regions covered by the rules were located on lands that the EPA understood at the time to be Indian country.[308] In contrast, within the geographic scope of this rulemaking, the EPA is aware of areas of Indian country within the borders of both Utah and Oklahoma with existing EGUs that meet the program's applicability criteria. Issues related to state, tribal, and Federal CAA implementation planning authority with respect to sources in Indian country in general and in these areas in particular are discussed in section III.C.2 of this document. EPA's approach for determining a portion of each state's budget for each control period that will be set aside for allocation to any units in areas of Indian country within the state not subject to the state's CAA implementation planning authority is discussed in section VI.B.9 of this document.

Units within the borders of each newly added state will join the Group 3 trading program on one of two possible dates during the program's 2023 control period (that is, the period from May 1, 2023, through September 30, 2023). The reason that two entry dates are necessary is that, as discussed in section VI.B.12.a of this document, the effective date is expected to fall after May 1, 2023. In the case of states (and Indian country within the states' borders) whose sources do not currently participate in the CSAPR NO_X Ozone Season Group 2 trading program—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the rule's effective date. However, in the case of the states (and Indian country within the states' borders) whose sources do currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin participating in the Group 3 trading program on May 1, 2023, regardless of the rule's effective date, subject to transitional provisions designed to ensure that the increased stringency of the Group 3 trading program as revised in this rulemaking will not substantively affect the sources' requirements prior to the rule's effective date. This approach provides a simpler transition for the sources historically covered by the Group 2 trading program than the alternative approach of being required to switch from the Group 2 trading program to the Group 3 trading program in the middle of a control period, and it is the same approach that was followed for sources that transitioned from the Group 2 trading program to the Group 3 trading program in 2021 under the Revised CSAPR Update. Section VI.B.12.a of this document contains further discussion of the rationale for this approach and the specific transitional provisions.

The EPA notes that under the rule, the expanded Group 3 trading program will include not only 19 states for which the EPA is determining that the required control stringency includes, among other measures, installation of new post-combustion controls, but also three

[305] Additional allowances available for compliance under the Group 3 trading program in the 2021 control period included a starting allowance bank created through mandatory conversion of a portion of the allowances banked under the Group 2 trading program as well as supplemental allowances issued to ensure that no provisions of the Revised CSAPR Update increasing regulatory stringency would take effect before that rule's effective date. *See* 86 FR 23133–137.

[306] The full-season emissions budgets for the 2023 control period under the Group 3 trading program and the incremental starting bank created in this action through conversion of additional Group 2 allowances (but not the bank of allowances carried over from the 2022 control period under the Group 3 trading program) will be prorated to reflect the portion of the 2023 ozone season occurring after the effective date of this rule. See sections VI.B.12.a. and VI.B.12.b.

[307] Such a rulemaking would not reopen any determinations which the Agency has made at Steps 1, 2, or 3 of the interstate transport framework in this action. Nor would it reopen any aspects of implementation of the program at Step 4 except for those in relation to establishing an auction and associated adjustments to ensure program stringency is maintained. In this respect, such a rulemaking would constitute a discretionary action that is not necessary to resolution of good neighbor obligations. Rather, these adjustments, if finalized, would reflect a shift from one acceptable form of implementation at Step 4 to a slightly modified but also acceptable form of implementation at Step 4, as related to EGUs. No legal or technical justification for this action as set forth in the record here depends on or would be undermined by the development of an alternative approach that includes an auction, and if the EPA for any reason determines not to propose or finalize such a rulemaking, no aspect of this rule would thereby be rendered infeasible or incomplete.

[308] CSAPR and the CSAPR Update both applied to EGUs located in areas within Oklahoma's borders that are now understood to be Indian country, consistent with the U.S. Supreme Court's decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020) (and subsequent case law), clarifying the extent of certain Indian country within Oklahoma's borders. However, those rules were issued before the *McGirt* decision. *See* section III.C.2.a.

states—Alabama, Minnesota, and Wisconsin—for which the EPA is determining that the required control stringency does not include such measures. In previous rulemakings, the EPA has chosen to combine states in a single multi-state trading program only where the selected control stringencies were comparable, to ensure that states did not effectively shift their emissions reduction requirements to other states with less stringent emissions reduction requirements by using net out-of-state purchased allowances. Although the assurance provisions in the CSAPR trading programs were designed to address the same general concern about excessive shifting of emissions reduction activities between states, EPA chose not to rely on the assurance provisions as sufficient to allow for interstate trading in situations where the states were assigned differing emissions control stringencies.

In this rulemaking, the EPA believes the previous concern about the possibility that certain states might not make the required emissions reductions is sufficiently addressed through the various enhancements to the design of the trading program, even where states have been assigned differing emissions control stringencies. First, the existing assurance provisions are being substantially strengthened through the addition of the unit-specific secondary emissions limitations discussed in sections VI.B.1.c.ii and VI.B.8. Second, by ensuring that individual units operate their emissions controls effectively, the unit-specific backstop daily emissions rate provisions discussed in sections VI.B.1.c.i and VI.B.7 will necessarily also ensure that required emissions reductions occur within the state. With these enhancements to the design of the trading program, the EPA does not believe it is necessary for sources in Alabama, Minnesota, and Wisconsin to be excluded from the revised Group 3 trading program simply because their emissions budgets reflect a different selected emissions control stringency than the other states in the program.

The EPA's legal and analytic bases for expansion of the Group 3 trading program to each of the additional covered states, as well as responses to the principal related comments, are discussed in sections III, IV, and V of this document, respectively, and responses to additional comments are contained in the *RTC* document. With respect to the proposed approach of including all states covered by the rule in a single trading program even where the assigned control stringencies differ, the only comments received by the EPA supported the approach, which is finalized as proposed.

3. Applicability and Tentative Identification of Newly Affected Units

The Group 3 trading program generally applies to any stationary, fossil-fuel-fired boiler or stationary, fossil fuel-fired combustion turbine located in a covered state (or Indian country within the borders of a covered state) and serving at any time on or after January 1, 2005, a generator with nameplate capacity exceeding 25 MW and producing electricity for sale, with exemptions for certain cogeneration units and certain solid waste incineration units. To qualify for an exemption as a cogeneration unit, an otherwise-affected unit generally (1) must be designed to produce electricity and useful thermal energy through the sequential use of energy, (2) must convert energy inputs to energy outputs with efficiency exceeding specified minimum levels, and (3) may not produce electricity for sale in amounts above specified thresholds. To qualify for an exemption as a solid waste incineration unit, an otherwise-affected unit generally (1) must meet the CAA section 129(g)(1) definition of a ''solid waste incineration unit'' and (2) may not consume fossil fuel in amounts above specified thresholds. The complete text of the Group 3 trading program's applicability provisions and the associated definitions can be found at 40 CFR 97.1004 and 97.1002, respectively. The applicability of this rule to MWCs and cogeneration units outside the Group 3 trading program is discussed in sections V.B.3.a and V.B.3.c of this document, respectively, and MWC applicability criteria are further discussed in section VI.C.6 of this document.

In this rulemaking, the EPA did not propose and is not finalizing any revisions to the existing applicability provisions for the Group 3 trading program. Thus, any unit that is located in a newly added state and that meets the existing applicability criteria for the Group 3 trading program will become an affected unit under the program. The fact that the applicability criteria for all of the CSAPR trading programs are identical therefore is sufficient to establish that any units that are currently required to participate in another CSAPR trading program in any of the additional states where such other programs currently are in effect—Alabama, Arkansas, Minnesota, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin (including Indian country within the borders of such states)—will also become subject to the Group 3 trading program.

In the additional states where other CSAPR trading programs are not currently in effect—Nevada and Utah (including Indian country within the borders of such states)—units already subject to the Acid Rain Program under that program's applicability criteria (*see* 40 CFR 72.6) generally also meet the applicability criteria for the Group 3 trading program. Based on a preliminary screening analysis of the units in these states that currently report emissions and operating data to the EPA under the Acid Rain Program, the Agency believes that all such units are likely to meet the applicability criteria for the Group 3 trading program.

Because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical, it is possible that some units could meet the applicability criteria for the Group 3 trading program even if they are not subject to the Acid Rain Program. Using data reported to the U.S. Energy Information Administration, in the proposal the EPA identified six sources in Nevada and Utah (and Indian country within the borders of the states) with a total of 15 units that appear to meet the general applicability criteria for the Group 3 trading program and that do not currently report NO_X emissions and operating data to the EPA under the Acid Rain Program. These units were listed in a table in the proposed rule, and the data from that table for these units are reproduced as Table VI.B.3–1 of this document. For each of these units, the table shows the estimated historical heat input and emissions data that the EPA proposed to use for the unit when determining state emissions budgets if the unit was ultimately treated as subject to the Group 3 trading program.[309] The EPA requested comment on whether each listed unit would or would not meet all relevant criteria set forth in 40 CFR 97.1004 and the associated definitions in 97.1002 to qualify for an exemption from the trading program and whether the estimated historical heat input and emissions data identified for each unit

[309] As discussed in section VI.B.10, any unit that becomes subject to the Group 3 trading program pursuant to this rule and that does not already report emissions data to the EPA in accordance with 40 CFR part 75 will not be required to report emissions data or be subject to allowance holding requirements under the Group 3 trading program until May 1, 2024, in order to provide time for installation and certification of the required monitoring systems. Such a unit will not be taken into account for purposes of determining state emissions budgets and unit-level allocations under the Group 3 trading program until the 2024 control period.

were representative. With respect to the listed units within the borders of Nevada or Utah, the EPA received no comments asserting either that the units qualified for applicability exemptions or that the estimated data identified by the EPA were unrepresentative.[310] For purposes of this rule, the EPA is therefore presuming that the units listed in Table VI.B.3–1 do not qualify for applicability exemptions and that the estimated data shown in the table for each unit are representative. However, the owners and operators of the sources retain the option to seek applicability determinations under the trading program regulations at 40 CFR 97.1004(c).

TABLE VI.B.3–1—ESTIMATED DATA TO BE USED FOR PRESUMPTIVELY AFFECTED UNITS WITHIN THE BORDERS OF NEVADA AND UTAH THAT DO NOT REPORT UNDER THE ACID RAIN PROGRAM

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Nevada	2322	Clark	GT4	CT	190,985	0.0475	
Nevada	2322	Clark	GT5	CT	1,455,741	0.0191	
Nevada	2322	Clark	GT6	CT	1,455,741	0.0187	
Nevada	2322	Clark	GT7	CT	1,455,741	0.0178	
Nevada	2322	Clark	GT8	CT	1,455,741	0.0204	
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTA	CT	660,100	0.0377	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTB	CT	660,100	0.0387	1
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val	GTC	CT	660,100	0.0387	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTA	CT	749,778	0.0323	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTB	CT	749,778	0.0370	1
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn	GTC	CT	749,778	0.0364	1
Nevada	56405	Nevada Solar One	HI	Boiler	479,452	0.1667	
Nevada	54271	Saguaro	CTG1	CT	1,383,149	0.0314	1
Nevada	54271	Saguaro	CTG2	CT	1,383,149	0.0301	1
Utah	50951	Sunnyside	1	Boiler	1,888,174	0.1715	

Table notes:
[1] Unit reports capability of producing both electricity and useful thermal energy.

4. State Emissions Budgets

In this final rule, the EPA is using a combination of a ''preset'' budget calculation methodology and a ''dynamic'' budget calculation methodology to establish state emissions budgets for the Group 3 trading program. A ''preset'' budget is one for which the absolute amount expressed as tons per ozone season control period is established in this final rule. It uses the latest data currently available on EGU fleet composition at the time of this final action. A ''dynamic'' budget is one for which the formula and emissions-rate information is finalized in this rule, but updated EGU heat input and inventory information is used on a rolling basis to set the total tons per ozone season for each control period. Both methods of budget calculation are designed to set budgets reflective of the emissions control strategies and associated stringency levels (expressed as an emissions rate of pounds of NO_X per mmBtu) identified for relevant EGU types at Step 3—which we will refer to in this section as the ''Step 3 emissions control stringency.'' Preset budgets provide greater certainty for planning purposes and can be reliably established in the short-term based on known, upcoming changes in the EGU fleet. Due to build time for new units and planning and approval processes for plant retirements, these major fleet alterations are often known several years in advance. This information facilitates presetting budgets that appropriately calibrate the identified control stringency to the fleet. Dynamic budgets better assure that the budgets remain commensurate with the Step 3 emissions control stringency over the longer term, as currently unknown changes in the EGU fleet occur. In this final rule, in response to comments, we have adjusted the proposal to give a greater role for preset budgets through 2029, while dynamic budgeting will be phased in to provide greater certainty in the short term and allow for a transition period to an exclusively ''dynamic'' approach beginning in 2030.

For the control periods from 2023 through 2025, the preset budgets established in the rule will serve as the state emissions budgets for the control periods in those years, with no role for dynamic budgeting. For the control periods from 2026 through 2029, the EPA is determining preset emissions budgets for each control period in the rule and will also calculate and publish dynamic budgets for each state in the year before each control period using the dynamic budget-setting methodology finalized in this rule, applied to data available at the time of the calculations. For these four control periods, each state's preset budget serves as a floor and may be supplanted by the dynamic emissions budget EPA calculates for the state for that control period only if the dynamic budget is higher than the preset budget. For control periods in 2030 and thereafter, the state emissions budgets will be the dynamic budgets calculated and published in the year before each control period.

In the dynamic budget calculation methodology, it is the fleet composition (reflected by heat input patterns across the fleet in service, inclusive of EGU entry and exit) that is dynamic, while the emissions stringency finalized in this rule is constant, as reflected in

[310] One commenter expressed the view that eight of the listed units within Nevada's borders appear to meet the CSAPR applicability criteria but provided no comments on the specific proposed data. See comments of Berkshire Hathaway Energy, EPA–HQ–OAR–2021–0668–0554, at 58–59. The EPA also received comments concerning sources within Delaware's borders that were included in the proposal's request for comment; these comments are moot because Delaware is not being added to the Group 3 trading program in the final rule. See comments of Calpine, EPA–HQ–OAR–2021–0668–0515; comments of Delaware City Refining, EPA–HQ–OAR–2021–0668–0309.

emissions rates for various types of units. Multiplying the assumed emissions rate for each unit (as finalized in this rule) by the identified recent historical heat input for each unit and summing the results to the state level would provide a given year's state dynamic emissions budgets. Dynamic budgets are a product of the formula promulgated in this action applied to a rolling three-year average of reported heat input data at the state level and a rolling highest-three-of-five-year average of reported heat input data at the unit level. As such, the EPA is confident that dynamic budgets will more accurately reflect power sector composition, particularly in later years, and certainly from 2030 and beyond, than preset budgets could and will therefore better implement the Step 3 emissions control stringency over long time horizons.

Starting in 2025 (for the 2026 control period), the dynamic budgets, along with the underlying data and calculations will be publicly announced, and this will occur approximately one year before the relevant control period begins. These will be published in the **Federal Register** through notices of data availability (NODAs), similar to how other periodic actions that are ministerial in nature to implement the trading programs are currently handled. And as with such other actions, interested parties will have the opportunity to seek corrections or administrative adjudication under 40 CFR part 78 if they believe any data used in making these calculations, or the calculations themselves, are in error.

To illustrate how dynamic budgeting will work after the transition from preset budgets, the dynamic budgets for the 2030 ozone season control period will be identified by May 1, 2029, using the latest available average of three years of reported operational data at that time (*i.e.,* the average of 2026–2028 heat input data at the state level and 2024–2028 years of rolling data at the unit level) applied in a simple mathematical formula finalized in this rule, which multiplies this heat input data by the emissions rates quantified in this rule. Therefore, if a unit retires before the start of the 2028 ozone season but had not announced its upcoming retirement at the time of this rule's finalization, the dynamic budget approach ensures that the dynamic budgets for 2030 and subsequent control periods would represent the identified control stringency applied to a fleet reflecting that retirement.

The two examples discussed next illustrate the implementation of the dynamic budget during the 2026–2029 time period. During this period, the state emissions budget for each state for a given control period will be the preset state emissions budget unless the dynamic budget is higher. This approach accommodates scenarios where baseline fossil heat input may exceed levels anticipated by EPA in the preset budgets (*e.g.,* this could result from greater electric vehicle penetration rates). Table VI.B.4–1 illustrates this scenario. In the preset budget approach for 2028, the 2028 heat input is estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021; see the subsection on preset budget methodology later in this section), which cannot reflect a subsequent change in fleet heat input values (column 2) due to, *e.g.,* increased utilization to meet increased electric load. However, the dynamic budget would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget. Therefore, the heat input values in column 2 under the dynamic scenario reflect the change in fleet utilization levels, and when multiplied by the emissions rates reflecting the Step 3 emissions control stringency in this final rule, the corresponding emissions (18,700 tons) summed in column 4 constitute a state budget that more accurately reflects the Step 3 emissions control stringency applied to the fleet composition for that year, as opposed to the 17,000 tons identified in the preset budget approach. As illustrated in the example, the dynamic variable is the heat input variable, which changes over time. In this instance, the dynamic budget value of 18,700 tons would be implemented for 2028 instead of the preset value, and thus accommodate the unforeseen utilization changes in response to higher demand.

In the second table, Table VI.B.4–2, the dynamic budget is lower than the preset budget due to retirements that were not foreseen at the time the preset budgets were determined. In the preset budget approach for 2028, the 2028 heat input is still estimated based on the latest available heat input data at the time of rule proposal (*i.e.,* 2021), which cannot reflect a subsequent fleet change in heat input values due to an unanticipated retirement of one of the state's coal-fired units before the start of the 2028 ozone season. However, the dynamic budget again would use 2022–2026 heat input values at the unit level and 2024–2026 heat input values at the state level—as opposed to 2021 heat input values—as the latest representative values to inform the 2028 state emissions budget, which would reflect the decline in coal heat input and replacement with natural gas heat input (capturing the coal unit's retirement). Therefore, the heat input values under the dynamic budget scenario reflect the change in fleet composition, and when multiplied by the relevant emissions rates reflecting the Step 3 emissions control stringency identified in this final rule, the corresponding emissions (15,000 tons) constitute a state budget that reflects the identified control stringency applied to the fleet composition for that year as opposed to the 17,000 tons in summed in the first table. However, for the 2026–2029 period, in which the EPA implements an approach that utilizes the higher of the dynamic budget or preset budget, the budget implemented for 2028 in this scenario would be the 17,000 ton preset amount.

During the 2026–2029 transition period—during which substantial, publicly announced utility commitments exist for higher emitting units to exit the fleet—it is still possible that yet-to-be known, unit-specific retirements (such as illustrated in this second scenario) may result in dynamic budgets that are lower than the preset budgets finalized in this rule. However, during this transition period EPA believes that having the preset budgets serve as floors for the state emissions budgets is appropriate for two primary reasons identified by commenters. First, commenters repeatedly emphasized the need for certainty and flexibility to successfully carryout plans for significant fleet transition through the end of the decade. The 2026–2029 period is expected to have substantial fleet turnover. Current Form EIA–860 data, in which utilities report their retirement plans, identify 2028 as the year with the most planned coal capacity retirements during the 2023–2029 timeframe. Using preset budgets as state emissions budget floors provides states and utilities with information on minimum quantities of allowances that can be used for planning purposes. In turn, this fosters the operational flexibility needed while putting generation and transmission solutions into place to accommodate such elevated levels of retirements. Second, the latter part of the decade has a significant amount of unit-level firm retirements already planned and announced for purposes of compliance with other power sector regulations or fulfillment of utility commitments. These known retirements are already captured in the preset state budgets, with the result that the likelihood and magnitude of instances where a state's dynamic budget for a given control period would be lower than its preset budget for the control period is reduced in this 2026–2029 period relative to control periods further in the future for which retirement plans have not yet been announced. After 2029, the dynamic budgets from 2030 forward will fully capture all prior retirements and new builds when the fleet is entering this period where unit-specific data on such plans is less frequently available. For instance, through the remaining portion of the decade, the amount of coal steam retirements identified and reported through Form EIA–860 is nearly 7 GW each year. However, for the decade beginning in 2030—the amount of capacity currently reported with a planned retirement is less than 2 GW each year.[311] This yet-to-be available data and relative lack of currently known firm retirement plans for 2030 and beyond make dynamic budget implementation for those years essential for state emissions budgets to maintain the Step 3 control stringency required under this rule.

TABLE VI.B.4–1—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF INCREASED FOSSIL HEAT INPUT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	660	0.05	16,500
Gas Units	400	0.01	2,000	440	0.01	2,200
State Budget (tons)			17,000			18,700

TABLE VI.B.4–2—EXAMPLE OF PRESET AND DYNAMIC BUDGET CALCULATION IN SCENARIO OF UNANTICIPATED RETIREMENT

	Preset budget approach (2028)			Dynamic budget approach (2028)		
	Preset heat input (tBtu)	Preset emissions rate (lb/mmBtu)	Preset tons (heat input × emissions rate)/2000	Heat input (tBtu)	Emissions rate (lb/mmBtu)	Tons (heat input × emissions rate)/2000
Coal Units	600	0.05	15,000	500	0.05	12,500
Gas Units	400	0.01	2,000	500	0.01	2,500
State Budget (tons)			17,000			15,000

In summary, for the control periods in 2023 through 2025, EPA is providing only preset budgets in this final rule because those control periods are in the immediate future and would not substantially benefit from the use of future reported data. For these years, the certainty around new builds and retirements is higher than ensuing years. For the ozone season control periods of 2026 through 2029, EPA is providing both preset budgets in this final rule and dynamic budgets via future ministerial actions. For those control periods from 2026 through 2029, the preset budgets finalized in this rule serve as floors, such that a given state's dynamic budget ultimately calculated and published for that control period will apply to that state's affected EGUs only if it is higher than the corresponding preset budget finalized in this rulemaking. This approach is in response to stakeholder comments requesting more advance notice regarding the total quantities of allowances available to accommodate compliance planning through the latter half of the decade, during a period of particularly high fleet transition expected with or without this rulemaking.

EPA's emissions budget methodology and formula for establishing Group 3 budgets are described in detail in the Ozone Transport Policy Analysis Final Rule TSD and summarized later in this section.

a. Methodology for Determining Preset State Emissions Budgets for the 2023 Through 2029 Control Periods

To compose preset state emissions budgets, the EPA is using the best available data at the time of developing this final rule regarding retirements and new builds. The EPA relies on a compilation of data from Form EIA–860 (where facilities report their future retirement plans), the PJM Retirement Tracker, utilities' integrated resource plans, notification of compliance plans with other EPA power sector regulatory requirements, and other information sources that EPA routinely canvasses to populate the data fields included in the Agency's NEEDS database. The EPA has updated this data on retirements and new builds using the latest information available from these sources at the time of final rule development as well as input provided by commenters.

For determining preset state emissions budgets, the EPA generally uses historical ozone season data from the 2021 ozone season, the most recent data available to EPA and to commenters responding to this rulemaking's proposal and providing a reasonable representation of near-term fleet conditions. This is similar to the approach taken in the CSAPR Update and the Revised CSAPR Update, where

[311] See 2021 Form EIA Form 860—Schedule 3, Generator Data. Department of Energy, Energy Information Administration.

the EPA likewise began with data for the most recent ozone season at the time of proposal (2015 and 2019, respectively).

By using historical unit-level NO_X emissions rates, heat input, and emissions data in the first stage of determining preset emissions budgets, the EPA is grounding its budgets in the most recent representative historical operation for the covered units at the time EPA began its final rulemaking. This data set is a reasonable starting point for the budget-setting process as it reflects recent publicly available and quality assured data reported by affected facilities under 40 CFR part 75, largely using CEMS. The reporting requirements include quality control measures, verification measures, and instrumentation to best record and report the data. In addition, the designated representatives of EGU sources are required to attest to the accuracy and completeness of the data.

The first step in deriving the future year state emissions budget is to calibrate historical data to planned future fleet conditions. EPA does this by adjusting this historical baseline information to reflect the known changes (*e.g.,* when deriving the 2023 state emissions budget, EPA starts by adjusting 2021 unit-level data to reflect changes announced and planned to occur by 2023). The EPA adjusted the 2021 ozone-season data to reflect committed fleet changes expected to occur in the baseline. This includes announced and confirmed retirements, new builds, and retrofits that occur after 2021 but prior to 2023. For example, if a unit emitted in 2021, but retired prior to May 1, 2022, its 2021 emissions would not be included in the 2023 baseline estimate. For units that had no known changes, the EPA uses the actual emissions, heat input, and emissions rates reported for 2021 as the baseline starting point for calculating the 2023 state emissions budgets. Using this method, the EPA arrived at a baseline emission, heat input, and emissions rate estimate for each unit for a future year (*e.g.,* 2023).

The second step in deriving the preset state emissions budgets is for EPA to take the adjusted historical data from Step 1, and adjust the emissions rates and mass emissions to reflect the control stringencies identified as appropriate for EGUs of that type. For instance, if an SCR-equipped unit was not operating its SCR so as to achieve a seasonal average emissions rate of 0.08 lb/mmBtu or less in the historical baseline, the EPA lowered that unit's assumed emissions rate to 0.08 lb/mmBtu and calculated the impact on the unit's mass emissions. Note that the heat input is held constant for the unit in the process, reflecting the same level of unit operation compared to historical 2021 data. The improved emissions rate of 0.08 lb/mmBtu is applied to this constant heat input, reflecting control optimization. In this manner, the unit-level totals from Step 1 are adjusted to reflect the additional application of the assumed control technology at a given control stringency. This is illustrated in Table VI.B.4.a–1. Row 1 reflects the 2021 historical data for this SCR-controlled unit. Row 2 reflects no change (as there are no known changes such as planned retirement or coal-to-gas conversion). Row 3 reflects application of the Step 3 stringency (*i.e.,* a 0.08 lb/mmBtu emissions rate from SCR optimization). The resulting impact on emissions is a reduction from the historical 4,700 tons to an expected future level of 615 tons. A state's preset budget for a given control period is the sum of the amounts computed in this manner for each unit in the state for the control period.

TABLE VI.B.4.a–1—EXAMPLE OF UNIT-LEVEL DATA CALCULATIONS FOR DERIVING STATE EMISSIONS BUDGETS

	Heat input (tBtu)	Emission rate (lb/mmBtu)	Emissions (tons)
Historical Data (2021)	15.384	0.61	4,700
Step 1 (Baseline)—Historical data adjusted for planned changes	15.384	0.61	4,700
Step 2—Baseline further adjusted for Step 3 stringency	15.384	0.08	615

For each control period from 2026 onward, the unit-specific emissions rates assumed for all affected states except Alabama, Minnesota, and Wisconsin will reflect the selected control stringency that incorporates post-combustion control retrofit opportunities for the relevant units identified in the state emissions budgets and calculations appendix to the Ozone Transport Policy Analysis Final Rule TSD. The emissions rates assigned to large coal-fired EGUs for 2026 state emissions budget computations only reflect 50 percent of the SCR retrofit emissions reduction potential at each of those units, to capture the phase-in approach EPA is taking for this control as described in section VI.A of this document. The EPA calculates these unit-level emissions rates in 2026 as the sum of the unit's baseline emissions rate and its controlled emissions rate divided by two (*i.e.,* 50 percent of the emissions reduction potential of that pollution control measure). The emissions rates assigned to these large coal-fired EGUs for 2027 state emissions budget computations reflect the full assumed SCR retrofit emissions potential at those units, by applying the controlled emissions rate only. For example, a coal steam unit greater than or equal to 100 MW currently lacking a SCR and emitting at 0.20 lb/mmBtu would be assumed to reduce its emissions rate to 0.125 lb/mmBtu rate in 2026 and 0.050 lb/mmBtu rate in 2027 for purposes of deriving its preset state emissions budgets in those years.

Comment: Some commenters suggested that EPA should not reflect planned retirements in its preset budgets. The suggestion stems from commenters' observation that those retirement decisions may yet change.

Response: The effectiveness of EPA's future year preset state emissions budgets depends on how well they are calibrated to the expected future fleet. Therefore, EPA believes it is important to incorporate expected new builds, retirements, and unit changes already slated to occur. Ignoring these factors would dilute, rather than strengthen, the ability of preset budgets to capture the most representative fleet of EGUs to which they will be applied. Omitting scheduled retirements and new builds from state emissions budgets would reflect units that power sector operators and planning authorities do not expect to exist, while failing to reflect units that are expected to exist.

EPA notes it is using the best available data at the time of the final rule. EPA relies on a compilation of data from Form EIA–860 where facilities report their future retirement plans. In addition, EPA is using data from regional transmission organizations who are cataloging, evaluating, and approving such retirement plans and data; data from notifications submitted directly to EPA by the utility themselves through comments; and retirement notifications submitted to permitting authorities. This information is highly reliable, real-world information that provides EPA with the high confidence that such retirements will in fact occur.

If a unit's future retirement does not occur on the currently scheduled date, EPA observes that such an unexpected departure from the currently available evidence would still not undermine the ability of affected EGUs to comply with their applicable state budgets. EPA's approach of using historical data and incorporation only of announced fleet changes in estimating its future engineering analytics baseline means that its future year baseline generation and retirement outlook for higher emitting sources is more likely to understate future retirements (rather than overstate as suggested by commenter), as EPA does not assume for the purpose of preset budget quantification any retirements beyond those that are already planned. In other words, in the 2023 through 2029 timeframe for which EPA is establishing preset state emissions budgets in this rulemaking, there are more likely to be additional future EGU retirements beyond those scheduled prior to the finalization of this rule than there are to be reversed or substantially delayed changes to already announced EGU retirement plans. For instance, subsequent to the EPA's finalization of the Revised CSAPR Update Rule budgets for 2023 (rule finalized in March 2021), the owners of Sammis Units 5–7 and Zimmer Unit 1 in Ohio (totaling nearly 3 GW of coal capacity) announced that the units would retire by 2023—nearly 5 years earlier than previously planned.[312] [313] These coal retirements were not captured in Ohio's 2023 or 2024 state emissions budgets established under the Revised CSAPR Update. Meanwhile, there have been no announcements of previously announced retirement plans being rescinded or delayed for other Ohio units. Similarly, the Joppa Power Plant in Illinois accelerated its retirement from 2025 to 2022 shortly after the Revised CSAPR Update Rule was signed.[314]

We further observe that the commenters' concern is only materially meaningful for the 2023 through 2025 preset budget periods, where the currently known information is generally the most reliable. For the 2026–2029 control periods, if an anticipated fleet change such as an EGU retirement does not actually occur, the dynamic budget setting methodology would, all else being equal, generate a budget reflective of that unit's continued operation (as the budget would be based on the preceding years of historical data), and that dynamic budget will supplant the preset budget for that state (if it represents a total quantity of emissions higher than the preset budget).

Because the future is inherently uncertain, all analytic tools and information resources used in any estimation of future EGU emissions will yield some differences between the projected future and the realized future. Such potential differences may either increase or decrease future emissions in practice, and the unavoidable existence of such differences does not, on its own, render the EPA's inclusion of currently announced retirements an unreasonable feature of the methodology for determining future year preset emissions budgets. To the contrary, if the EPA failed to include these announced retirements, the rule would knowingly authorize amounts of additional, sustained pollution that are not currently expected to occur. If those retirements largely or entirely occur as currently scheduled, the overestimated state budgets would allow other EGUs to emit additional pollution in place of the emissions from the retired EGUs instead of maintaining or improving their emissions performance to eliminate significant contribution with nonattainment and interference with maintenance of the NAAQS.[315]

Additionally, as noted elsewhere, EPA's use of a market-based program, a starting bank of converted allowances, and variability limits are all features that will readily accommodate whatever relatively limited differences in emissions may occur if a currently scheduled EGU retirement is ultimately postponed during the preset budget years of 2023 through 2025. Therefore, EPA's resulting preset state emissions budgets—inclusive of expected fleet turnover—are robust to the inherent uncertainty in future year baseline conditions for the period in which they are applied.

Comment: Some commenters suggested that EPA should use a multi-year baseline for all of its state budget derivations, including preset budgets, to control for outlier years that may not be representative of future years due to major weather events or other fleet disruptions (such as a large nuclear unit outage).

Response: For preset state emissions budget derivation, EPA is finalizing use of the same single-year[316] historical baseline approach it used in the proposed rule. This approach is similar to the Revised CSAPR Update, where EPA also relied on a single-year historical baseline to inform its Step 3 approach. EPA's interest in a historical data set to inform this part of the analysis is to capture the most representative view of the power sector. For estimating preset state budgets, EPA finds that, particularly at the state level, more recent data is a better representation and basis for future year baselines rather than incorporating older data. Taking as an example preset budget estimation for the 2023 through 2025 ozone seasons, the EPA is able to compare its single-year base line to an alternative multi-year baseline (*e.g.,* a 3-year baseline encompassing 2020–2022) and determine that the single year baseline better reflects future fleet operation expectation than a multi-year baseline that incorporates units which have since retired as well as outlier patterns in load during pandemic-related shutdowns.

EPA recognizes that 2021 is the latest available historical data as of the preparation of this rulemaking, and therefore the most up-to-date picture of the fleet at the time EPA began its analysis. EPA then further evaluates the 2021 historical data at the state level to determine whether it was a representative starting point for estimating future year baseline levels and subsequently deriving the preset state emissions budgets. If the Agency finds any state-level anomalies, it makes necessary adjustments to the data. While unit-level variation may occur from year-to-year, those variations are often offset by substitute generation from other units within the state. Therefore, EPA conducts its first screening at the state level by identifying any states where 2021 heat

[312] Available at *https://www.prnewswire.com/news-releases/energy-harbor-transitions-to-100-carbon-free-energy-infrastructure-company-in-2023-301501879.html*.

[313] Available at *https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/coal/071921-vistra-plans-to-retire-13-gw-zimmer-coal-plant-in-ohio-five-years-early*.

[314] Available at *https://www.prnewswire.com/news-releases/joppa-power-plant-to-close-in-2022-as-company-transitions-to-a-cleaner-future-301263013.html*.

[315] Some of these announced retirements reflect the operator's reported intention to EPA to retire the affected capacity by that time as part of their compliance with effluent limitation guidelines or with the coal combustion residuals rule.

[316] For the purposes of this rulemaking, when describing a ''year'' or ''years'' of data utilized in state emission budget computations, the EPA is actually utilizing the relevant data from May 1 through September 30 of the referenced year(s), consistent with the control period duration of this rule's EGU trading program.

input and 2021 emissions were the lowest year for heat input and emissions relative to the past several years (2018–2022, excluding 2020 due to shut downs and corresponding reduced utilization related to the pandemic onset).[317 318] Then, for that limited number of states (AL, LA, MS, and TX) in which 2021 reflects the minimum fossil fuel heat input and minimum emissions over the baseline evaluation period, EPA—similar to prior rules—evaluated whether any unit-level anomalies in operation were driving this lower heat input at the state level. EPA examined unit-level 2021 outages to determine where an individual unit-level outage might yield a significant difference in state heat input, corresponding emissions baseline and resulting state emissions budgets. When applying this test to all of the units in the previously identified states (and even when applying to EGUs in all states for whom Federal implementation plans are finalized in this rulemaking), the EPA determined that the only unit with a 2021 outage that (1) decreased its output relative to preceding or subsequent years by 75 percent or more (signifying an outage), and (2) could potentially impact the state's emissions budget substantially as it constituted more than 5 percent of the state's heat input in a non-outage year was Daniel Unit 2 in Mississippi. EPA therefore adjusted this state's baseline heat input and NO_X emissions to reflect the operation of this unit based on its 2019 data—which was the second most recent year of data available at the time of proposal (excluding 2020 given atypical impacts from pandemic-related shutdowns) for which this unit operated. The EPA then applied the Step 3 mitigation strategies as appropriate to this unit (*i.e.,* combustion controls upgrade in 2024, SCR retrofit in 2026/2027) to derive this portion of Mississippi's budget. This test, and subsequent adjustment as necessary, enables EPA to utilize the latest, most representative data in a manner that is robust to any substantial state-level or region-level outlier events within that dataset and further validates EPA's comprehensive approach to using the most recent single year of data for preset budgets.

b. Methodology for Determining Dynamic State Emissions Budgets for Control Periods in 2026 onwards

In this final rule, the EPA is finalizing an approach of using multi-year baseline data for purposes of dynamic budget computation. The aforementioned testing of the representative nature of a single year of baseline data for purposes of preset budget setting is not possible in the dynamic budget process as that data will not be available until a later date. Further, the EPA generally agrees with commenters that use of a multi-year period will be more robust to any unrepresentative outlier years in fleet operation and thus better suited for purposes of dynamic budgets. The methodology for determining dynamic state emissions budgets for later control periods (2026 and beyond) relies on a nearly identical methodology for applying unit-level emissions rate assumptions as the preset budget methodology. But it uses more recent heat input data that will become available by that future time, employing a multi-year approach for identifying the heat input data so as to ensure representativeness.

For dynamic budgets, EPA uses more years of baseline data to control for any state-level and unit-level variation that may occur in a future single year that is not possible to identify at present. First, for each unit operating in the most recent ozone season for which data have been reported, EPA identifies the average of the three highest unit-level heat input values from the five ozone seasons ending with that ozone season to get a representative unit-level heat input. Ozone seasons for which a unit reported zero heat input are excluded from the averaging of the three highest heat input values for that unit. These representative unit-level heat input values established for each unit individually are then summed for all units in each state. Each unit's representative unit-level heat input is then divided into this state-level sum to get that unit's representative percent of the aggregated average heat input values for all affected EGUs in that state.

Next, EPA calculates a representative state-level heat input by taking the average state-level total heat input across affected EGUs from the most recent three ozone seasons for which data have been reported, to which the above-derived representative unit-level percentages of heat input are applied. The EPA uses a three-year baseline period for state-level heat input versus the five-year baseline period noted previously for unit-level heat input because there is less variation from year to year at the state level compared to the unit level. Multiplying the representative unit-level percentages of heat input by the representative state-level heat input yields a normalized unit-level heat input value for each affected EGU. This step assures that the total heat input being reflected in a dynamic state budget does not exceed the average total heat input reported by affected EGUs in that state from the three most recent years. Finally, each normalized unit-level heat input value is multiplied by the emissions rate reflecting the assumed unit-specific control stringency for each particular year (determined at Step 3) to get a unit-level emissions estimate. These unit-level emissions estimates are then summed to the state level to identify the dynamic budget for that year. This procedure to derive normalized unit-level heat input is captured in the following table:

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT

[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
Unit A	100	200	150	200	300	233	41%	483	199
Unit B	50	100	200	50	100	133	24	483	114
Unit C	250	150	150	200	100	200	35	483	170

[317] EPA identified states for which 2021 both heat input and emissions were the low year among the examined baseline period as a preliminary screen to identify potential instances where reduced utilization may lead to an understated emissions baseline value.

[318] EPA also conducted a similar test to identify states in which 2021 heat input and emissions were the high year among the examined baseline period and found that it was for both Utah and Pennsylvania. However, for both states the elevated heat input trend persisted into 2022 (at slightly lower levels and was correlated with retirements elsewhere in the region—indicating that some of this heat input increase may be representative of the future fleet and that planned retirements factored into preset budget will remove any unrepresentative heat input from 2021.

TABLE VI.B.4.b–1—DERIVATION OF NORMALIZED UNIT-LEVEL HEAT INPUT—Continued

[Illustrative]

	2022 Heat input	2023 Heat input	2024 Heat input	2025 Heat input	2026 Heat input	Representative unit-level heat input (avg of 3 highest of past 5)	Representative unit-level percent	Representative state level heat input (avg 3 most recent state totals)	Normalized unit—level heat input
State Total	400	450	500	450	500	567			

The EPA will issue these dynamic budget quantifications approximately 1 year before the relevant control period. We view such actions as ministerial in nature in that no exercise of agency discretion is required. For instance, starting in early 2025, the EPA would take the most recent three years of state-level heat input data and the most recent five years of unit-level heat input data and calculate 2026 state emissions budgets using the methodology described previously. For 2026–2029, EPA is establishing the preset state emissions budgets finalized in this rulemaking and will only supplant those preset emissions budgets with the to-be-published dynamic emissions budgets if, for a given state and a given control period, that dynamic budget yields a higher level of emissions than the corresponding preset budget finalized in this rulemaking. For 2030 and beyond, the EPA solely uses the dynamic budget process.

By March 1 of 2025, and each year thereafter, the EPA will make publicly available through a NODA the preliminary state emissions budgets for the subsequent control period and will provide stakeholders with a 30-day opportunity to submit any objections to the updated data and computations. (This process will be similar to the releases of data and preliminary computations for allocations from new unit set-asides that is already used in existing CSAPR trading programs.) By May 1 of 2025, and each year thereafter, the EPA will publish the dynamic budgets for the ozone-season control period in the following calendar year. Through the 2029 ozone season control period, these budgets will only be imposed if the applicable dynamic state budget is higher than the corresponding preset state budget finalized in this rulemaking. Preliminary and final unit-level allowance allocations for the units in each state in each control period will be published on the same schedule as the dynamic budgets for the control period. For the control periods from 2026 through 2029, the allocations will reflect the higher of the preset or dynamic budget for each state, and after 2030, the allocations will reflect the dynamic budgets. Additional details, corresponding data and formulas, and examples for the dynamic budget are described in the Ozone Transport Policy Analysis Final Rule TSD.

Comment: Multiple commenters claimed that designing a dynamic budget process that relies on a single year of yet-to-be known heat input data may produce an unrepresentative view of fleet operations for the immediate ensuing years. Commenters pointed to the hypothetical of another pandemic-like year (*e.g.,* 2020) occurring in the future, noting that 2020 would have been a poor choice for estimating 2022 fleet operation and the same would likely hold true if a similar event occurred, for example, in 2025—that would consequently make that year a poor choice as a representative of 2027 baseline. They further pointed out that severe weather events and operating disruptions (a large nuclear plant outage) can similarly render a single year baseline a risky choice to inform future expectations.

Response: Insofar as the commenters are addressing the reference period for dynamic budget computation regarding years of data that have not yet occurred and therefore not currently available for evaluating their representative nature, EPA agrees and is incorporating a rolling 3-year baseline at the state level and a rolling 5-year baseline at the unit level for determining dynamic budgets in this final rule. These multi-year rolling baseline (or reference periods) will minimize any otherwise undue impact from individual years where fleet-level or unit-level heat input was uncharacteristically high or low. EPA determined that such an approach, while not needed for preset budgets, is necessary in the case of dynamic budgets because the baseline in that instance is occurring in a future year and therefore is not knowable and available to test for representativeness at the time of the final rule. To control for this type of uncertainty, the EPA finds it appropriate to use a multi-year baseline in this instance per commenter suggestion. While a multi-year baseline may have a slight drawback of using a slightly more dated past fleet performance (including emissions from higher emitting EGUs that may have subsequently reduced utilization by the target year for which the dynamic budget is being calculated) to estimate the expected future fleet performance at the emissions performance levels determined by the Step 3 result in this rulemaking, that drawback is worth the advantage of protecting against instances where atypical circumstances in the most recent single year may occur and not be representative of the subsequent year for which the dynamic budget is being estimated. This singular drawback of moving to a multi-year baseline is most pronounced in the early years of dynamic budgeting. Therefore, EPA is able to lessen the impact of this drawback of the multi-year baseline by extending the earliest start date of dynamic budgets from 2025 (as proposed) to 2026 in the final rule.

Comment: Commenters suggested that the dynamic budget procedure would not provide enough advance notice of state budget and unit level allocation for sources to adequately plan future year operation.

Response: EPA disagrees with the notion that the timing of the dynamic budget determination would occur too close to the control period to allow adequate operations planning for compliance. As described previously, the dynamic budget level would be provided approximately 1 year in advance of the start of the control period (*i.e.,* around May 1), and the allowance allocations would occur on July 1, approximately 10 months prior to the start of the compliance period. Not only is this an adequate amount of time as demonstrated by the successful implementation of past rules that have been finalized and implemented within several months of the beginning of the first affected compliance period (*e.g.,* Revised CSAPR Update), but EPA notes it is maintaining similar trading program flexibility and banking flexibilities of past programs which provide further opportunities for sources to procure allowances and plan for any future operating conditions. Finally, as noted previously, the EPA is providing preset budgets for the years 2023–2029, which serve as an effective floor on the state's ultimate emissions budget level for years 2026–2029, as states will receive the higher of the preset or dynamic budget for those years. This provision of certain preset state emissions budgets serving as a floor level for 2026–2029 should further assuage commenters' concerns regarding planning certainty about allowance allocations and state emissions budget levels during this period of power sector transition to cleaner energy sources.

Comment: Commenters raised concerns that there is a two-year lag in the dynamic budgets in that, for example, for the dynamic budget in the 2026 control period, the calculations will be based on heat input and inventory information reflective of data through 2024. Commenters contend that, if there is a much greater need for allowances for compliance due to unavoidable or unforeseen need for a higher amount of heat input than reflected in prior years' data, the budget for that control period will not reflect this need, and the allowances will only become available when the dynamic budget is calculated using that information (*i.e.,* 2025 data would be reflected starting in the 2027 dynamic budget). According to commenters, this lag could present a serious compliance challenge. Other commenters raised a concern in the opposite direction about the potential ''slack'' created by the lag time—meaning that as high-emitting units retire, their emissions and operation will still inform the state emissions budgets for additional years beyond their retirement due to the lag.

Response: The EPA recognizes there will be a data lag inherent in the computation of future year dynamic emissions budgets, because the dynamic budgets will reflect fleet composition and utilization data from recent previous control periods rather than the control periods for which the dynamic budgets are being calculated. This means that the resulting dynamic budgets will reflect a limited lag behind the actual pace of the EGU fleet's trends. However, on the whole, those trends are clearly toward more efficient and cleaner generating resources. Thus, the data lag on the whole will inure to the compliance benefit of EGUs by resulting in dynamic budgets that are generally calculated at levels likely to be somewhat higher than what a dynamic budget calculation reflecting real-time EGU operations would produce. The EPA believes this data lag is worthwhile to provide more compliance planning certainty and advance notice to affected EGUs of the dynamic budget applicable to an upcoming control period. Furthermore, this data lag in dynamic budget computation is comparable to the data lag of quantifying preset state budgets for 2023 through 2025 based upon 2021 data, and at no point in the long history of EPA's trading programs has such a data lag in state budget computation yielded any compliance problems for affected EGUs. Without dynamic budgeting, the data lag inherent in calculating preset budgets would grow unabated with the passage of time, as a fixed reference year of heat input levels would continually apply regardless of potentially higher heat input levels farther and farther into the future. By eliminating the increase in the length of the data lag, this new dynamic budgeting approach is a substantial improvement in performance of the program relative to previous approaches that were not capable of capturing changes over time in the fleet and its utilization beyond the scheduled changes known to the EPA at the time of establishing preset budgets.

The EPA disagrees that this lag will in fact pose compliance challenges for EGUs even if the unlikely scenario described by commenters were to occur. Several factors influence this. First, the change in methodology to preset budgets serving as a floor on budgets through 2029 means that the dynamic budget methodology can only produce an increase in the budget from this final rule through that year. Second, the adoption of a multi-year approach for identifying the heat input used to calculate the dynamic budgets will smooth the year-to-year budget changes and effectively eliminate the possibility of greatest concern, which was that a single year of unusually low heat input would be used to set the budget for a subsequent year that turned out to have unusually high heat input. While a year of unusually high heat input for a given state may still occur, the state's budgets for those years will never be based on heat input from an anomalously low year, but instead will always be based on an average of several years' heat input. Third, because the Group 3 trading program is an interstate program implemented over a wide geographic region, and it is unlikely that all regions of the country would uniformly experience a marked increase in fossil fuel heat input necessitating an additional supply of allowances, it is likely that allowances will be available for trade from one area of the country where there is less demand to another area where there is greater demand. Fourth, as explained in section VI.B.5 of this document, each state's assurance level will adjust to reflect actual heat input in that year. Specifically, the EPA will determine each state's variability limit for a given control period so that the percentage value used will be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total reported heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. Thus, if in year 2030, for example, a state's actual heat input levels increase to a level that is not reflected in the dynamic budget calculation using earlier years of data, the assurance level (which absent the unusually high heat input would be 121 percent of the state's budget) will be calculated by the EPA following the 2030 ozone season, using that higher reported heat input. This will avoid imposing a three-for-one allowance surrender penalty on sources except where emissions exceed the assurance level even factoring in the increase in heat input in that year. Finally, as some commenters observed, the inherent data lag in dynamic budget quantification means that a state budget for the year 2030 will continue to reflect emissions from any EGU that retires before the 2030 control period but is still operating anytime during the 2026–2028 reference years from which the 2030 dynamic budget will be calculated. Given the likely ongoing trend of relatively high-emitting EGU retirements over time, this method for determining dynamic budgets should further assist the ability of remaining EGUs to obtain sufficient allowances to cover future heat input levels.

With respect to the comments expressing concern that dynamic budgets would create too much slack because of the lag in incorporating retirements, the EPA observes that dynamic budgets will yield a closer representation of Step 3 control stringency across the future fleet than preset budgets for years in which retirement plans are currently relatively unknown. Moreover, any risk that the lag would lead to an unacceptably large surplus of allowances is limited by EPA's finalization of the annual bank recalibration to 21 percent and 10.5 percent of the budget beginning in 2024 and 2030 respectively. The corresponding risk that a lag will lead sources to not operate emissions controls, due to a surplus of allowances, is also limited by the backstop daily emissions rates that start in 2024 (for sources with existing SCR controls) and no later than 2030 for other coal-fired sources.

Comment: Commenters allege that the dynamic budget methodology is effectively a ''one-way ratchet'' because, if EGUs pursue compliance strategies such as reduced utilization or generation shifting to comply with the rule rather than install or optimize pollution controls pursuant to the identified Step 3 emissions control strategies, the effect will be that the dynamic budget calculated in a future year will reflect that reduced heat input, but the applied emissions rate assumption will be the same. Thus, the approach according to commenters actually ''punishes'' sources for achievement of emissions reductions commensurate with EPA's Step 3 determinations through alternative compliance means, by producing a smaller budget in later years (less heat input multiplied by the same emissions rate). If the source again reduces utilization or shifts generation to comply with this budget, then budgets in later years will again ratchet down, and so on.

Response: First, the claims of dynamic budgeting being a one-way ratchet are incorrect. As pointed out at proposal, the dynamic budget process would allow for increased utilization to result in increased budgets. Moreover, this concern is entirely mooted for the period 2026 through 2029 with the shift to preset budgets serving as a floor; dynamic budgeting can only increase the budget used in any given year in this time period. Additionally, the use of a multi-year average heat input in the budget-setting calculations will, on the whole, modulate the dynamic budgets such that the budgets over time will only gradually change with changes in the operating profile of the EGU fleet.

For the control periods 2030 and later, this rule is premised on the expectation that all large coal-fired EGU sources identified for SCR-retrofit potential will, if they continue operating in 2030 or later, have installed the requisite post-combustion controls. Thus, the backstop daily emissions rate applies for all such sources beginning in the 2030 ozone season. In this latter period (post-2030), the EPA disagrees that the dynamic budget will punish fleet segments seeking to continue to pursue a strategy of reduced utilization. Rather, the dynamic budget will simply continue to reflect the Step 3 emissions control stringency. For instance, if there are two otherwise high-emitting sources in a state that can reduce emissions by operating SCR, this rule's control stringency finds it cost effective for both sources to operate their controls. If one source retires and is replaced by new lower-emitting generation, it is not a punishment to have the budgets adjust in a way that still incentivize remaining units to operate their controls. This is simply right-sizing the budget to an evolving fleet. It is a feature of the rule, not a flaw, and is designed to address observed instances in prior rules where market-driven reduced utilization resulted in non-binding (*i.e.,* overly slack) budgets and corresponding conditions where the incentive to operate a control dissipated over time. In the event that sources reduce utilization whether for compliance purposes or market-driven reasons, that also does not obviate the importance of continuing to incentivize the Step 3 emissions control stringency at identified sources.

c. Final Preset State Emissions Budgets

For affected EGUs in each covered state (and Indian country within the state's borders), this final rule establishes preset budgets for the control periods 2023 through 2029. For control periods 2026 through 2029, any of those preset budgets may be supplanted by the corresponding dynamic budget that will be tabulated at later date, if and only if that dynamic budget yields a higher amount. For 2030 and beyond, the dynamic budget formula promulgated in this rule will be applied to future year data to quantify state emissions budgets for those control periods. The procedures for allocating the allowances from each state budget among the units in each state (and Indian country within the state's borders) are described in section VI.B.9 of this document. The amounts of the final preset state emissions budgets for the 2023 through 2029 control periods are shown in Table VI.B.4.c–1.

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS

[Tons] [a b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Alabama	6,379	6,489	6,489	6,339	6,236	6,236	5,105
Arkansas	8,927	8,927	8,927	6,365	4,031	4,031	3,582
Illinois	7,474	7,325	7,325	5,889	5,363	4,555	4,050
Indiana	12,440	11,413	11,413	8,410	8,135	7,280	5,808
Kentucky	13,601	12,999	12,472	10,190	7,908	7,837	7,392
Louisiana	9,363	9,363	9,107	6,370	3,792	3,792	3,639
Maryland	1,206	1,206	1,206	842	842	842	842
Michigan	10,727	10,275	10,275	6,743	5,691	5,691	4,656
Minnesota	5,504	4,058	4,058	4,058	2,905	2,905	2,578
Mississippi	6,210	5,058	5,037	3,484	2,084	1,752	1,752
Missouri	12,598	11,116	11,116	9,248	7,329	7,329	7,329
Nevada	2,368	2,589	2,545	1,142	1,113	1,113	880
New Jersey	773	773	773	773	773	773	773
New York	3,912	3,912	3,912	3,650	3,388	3,388	3,388
Ohio	9,110	7,929	7,929	7,929	7,929	6,911	6,409
Oklahoma	10,271	9,384	9,376	6,631	3,917	3,917	3,917
Pennsylvania	8,138	8,138	8,138	7,512	7,158	7,158	4,828
Texas	40,134	40,134	38,542	31,123	23,009	21,623	20,635
Utah	15,755	15,917	15,917	6,258	2,593	2,593	2,593
Virginia	3,143	2,756	2,756	2,565	2,373	2,373	1,951
West Virginia	13,791	11,958	11,958	10,818	9,678	9,678	9,678
Wisconsin	6,295	6,295	5,988	4,990	3,416	3,416	3,416

TABLE VI.B.4.c–1—CSAPR NO_X OZONE SEASON GROUP 3 PRESET STATE EMISSIONS BUDGETS FOR THE 2023 THROUGH 2029 CONTROL PERIODS—Continued

[Tons] [a b]

State	Final emissions budgets for 2023	Final emissions budgets for 2024	Final emissions budgets for 2025	Preset emissions budgets for 2026	Preset emissions budgets for 2027	Preset emissions budgets for 2028	Preset emissions budgets for 2029
Total	208,119	198,014	195,259	151,329	119,663	115,193	105,201

Table Notes:

[a] The state emissions budget calculations pertaining to Table VI.B.4.c–1 are described in greater detail in the Ozone Transport Policy Analysis Final Rule TSD. Budget calculations and underlying data are also available in Appendix A of that TSD.

[b] In the event this final rule becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period will be adjusted under the rule's transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date. The 2023 budget amounts shown in Table VI.B.4.c–1 do not reflect these possible adjustments. The transitional provisions are discussed in section VI.B.12 of this document.

5. Variability Limits and Assurance Levels

Like each of the other CSAPR trading programs, the Group 3 trading program includes assurance provisions designed to limit the total emissions from the sources in each state (and Indian country within the state's borders) in each control period to an amount close to the state's emissions budget for the control period, consistent with the principle that each state's sources must be held to the elimination of significant contribution within that state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability beyond sources' reasonable ability to control. For each state, the assurance provisions establish an assurance level for each control period, defined as the sum of the state's emissions budget for the control period plus a variability limit, which under the Group 3 trading program regulations in effect before this rulemaking was 21 percent of the relevant state emissions budget. The purpose of the variability limit is to account for year-to-year variability in EGU operations, which can occur for a variety of reasons including changes in weather patterns, changes in electricity demand, and disruptions in electricity supply from other units or from the transmission grid. Because of the need to account for such variability in operations of each state's EGUs, the fact that emissions from the state's EGUs may exceed the state's emissions budget for a given control period is not treated as inconsistent with satisfaction of the state's good neighbor obligations as long as the total emissions from the EGUs remain below the state's assurance level. Emissions from a state's EGUs above the state's emissions budget but below the state's assurance level are treated in the same manner as emissions below the state's emissions budget in that such emissions are subject to the same requirement to surrender allowances at a ratio of one allowance per ton of emissions. In contrast, emissions above the state's assurance level for a given control period are strongly discouraged as inconsistent with the state's good neighbor obligations and are subject to an overall 3-for-1 allowance surrender ratio. The establishment of assurance levels with associated extra allowance surrender requirements was intended to respond to the D.C. Circuit's holding in *North Carolina* requiring the EPA to ensure within the context of an interstate trading program that sources in each state are required to address their good neighbor obligations within the state and may not simply shift those obligations to other states by failing to reduce their own emissions and instead surrendering surplus allowances purchased from sources in other states.[319]

In this rulemaking, the EPA did not propose and is not making changes to the basic structure of the Group 3 trading program's assurance provisions, which will continue to set an assurance level for each control period equal to the state's emissions budget for the control period plus a variability limit and will continue to apply a 3-for-1 surrender ratio to emissions exceeding the state's assurance level.[320] Each assurance level also will continue to apply to the collective emissions of all units within the state and Indian country within the state's borders.[321] However, the EPA is making a change to the methodology for determining the variability limits. Specifically, the EPA will determine each state's variability limit for a given control period so that, instead of always multiplying the state's emissions budget for the control period by a value of 21 percent, the percentage value used will be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total historical heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. For example, if the total reported heat input of the state's covered sources for the 2025 control period is 130 percent of the historical heat input used in computing the state's 2025 budget, then the state's variability limit for the 2025 control period will be 30 percent of the state's emissions budget instead of 21 percent of the state's emissions budget. The EPA expects that the minimum 21 percent will apply in almost all instances, and that the alternative, higher percentage value will apply only in control periods where operational variability causes an unusually large increase relative to the historical data used in setting the state's emissions budget, which would be a situation meriting a temporarily higher variability limit and assurance level. The revised methodology for determining the variability limits will apply both with respect to control periods when a state's emissions budget is a preset budget established in this final rule and with respect to control periods when a state's emissions budget is a dynamically-determined budget computed using the procedures laid out in the regulations, and it will apply starting with the 2023 control period rather than starting with the 2025 control period as proposed.

The purpose of the revision to the variability limits is to better align the variability limits for successive control periods with the heat input data used in setting the state emissions budgets. Under the final rule, each dynamically

[319] 531 F.3d at 908.

[320] As discussed in section VI.B.8, the EPA is also establishing a new secondary emissions limitation for individual units that will apply in situations where an exceedance of the relevant state's assurance level has occurred.

[321] *See* 40 CFR 97.1002 (definitions of "common designated representative," "common designated representative's assurance level" and "common designated representative's share"), 97.1006(c)(2), and 97.1025.

determined emissions budget will be computed using the latest available reported heat input, which for each budget set for a control period in 2026 or a later year will be the average state-level heat input for the control periods two, three, and four years before the control period whose budget is being determined (for example, the dynamic state emissions budgets for the 2026 control period will be computed in early 2025 using the reported state-level heat input for the 2022–2024 control periods). The revised variability limits will be well coordinated with the budgets established using this dynamic budgeting process, because the percentage change in the actual heat input for the control period relative to the earlier multi-year average heat input used in computing the state's emissions budget will be an appropriate measure of the degree of operational variability actually experienced by the state's EGUs in the control period relative to the assumed operating conditions reflected in the state's budget. Setting a variability limit in this manner is thus entirely consistent with the overall purpose of including variability limits in the assurance provisions.

As discussed in sections VI.B.1.b.i and VI.B.4, for the 2023–2025 control periods the state emissions budget for a given control period will be the preset budget determined in this rule, and for the 2026–2029 control periods, the state emissions budget for a given control period will be the preset budget determined in this rule rather than the dynamically determined budget computed in the year before the control period unless the dynamic budget is higher than the preset budget. If the state emissions budget is the preset budget, the historical heat input data reflected in that budget will be the heat input data for the 2021 control period, adjusted to reflect projected changes in fleet composition over time that are known at the time of this rulemaking, but not adjusted to reflect changes in fleet composition that are not known at the time of the rulemaking or changes in the utilization of individual units.[322] In this case, the variability limit for the control period would be the higher of 21 percent or the percentage change in the actual heat input for the control period relative to the heat input for the 2021 control period as adjusted to reflect the projected changes in fleet composition. The EPA believes it is reasonable to apply the same principle in setting the variability limit in control periods where the preset floor budgets are used as in control periods where the dynamically determined budgets are used, because the preset floor budgets are computed using the same principles as the dynamically determined budgets, with the major difference being that the available heat input data used in computing the preset budgets are necessarily less current. Accordingly, because preset budgets established in this manner are used starting with the 2023 control period, the EPA believes it is also reasonable to begin implementing the revised methodology for determining variability limits starting with the 2023 control period.

The reason the EPA is using the higher of a fixed 21 percent or the percentage change in heat input computed as just described is that the EPA believes that, for operational planning purposes, it can be useful for sources to know in advance of the control period a minimum value for what the variability limit could turn out to be. Because a state's actual total heat input for a control period is not known until after the end of the control period, this revision will have the consequence that the state's final variability limit and assurance level for the control period also will not be known until after the control period. However, because the rule provides that the variability limit will always be at least 21 percent, the sources in a state will be able to rely for planning purposes on the knowledge that the assurance level will always be at least 121 percent of the state's emissions budget for the control period. Advance knowledge of the minimum possible amount of the assurance level can be useful to sources, because one way a fleet owner can be confident that it will never incur the 3-for-1 allowance surrender ratio owed for emissions exceeding its state's assurance level is to plan its operations so as to never allow the emissions from its fleet to exceed the fleet's aggregated share of the state's assurance level for the control period. Knowing that the variability limit will always be at least 21 percent will provide sources with minimum values they could use for such planning purposes.

The EPA believes that 21 percent is a reasonable value to use as the minimum variability limit. To determine appropriate variability limits for the trading programs established in CSAPR, the EPA analyzed historical state-level heat input variability over the period from 2000 through 2010 as a proxy for emissions variability, assuming constant emissions rates. *See* 76 FR 48265. Based on that analysis, the variability limits for ozone season NO_X in both CSAPR and the CSAPR Update were set at 21 percent of each state's budget, and these variability limits for the NO_X ozone season trading programs were then codified in 40 CFR 97.510 and 97.810, along with the respective state budgets.[323] For the Revised CSAPR Update, the EPA performed an updated variability analysis for the twelve states being moved into the Group 3 trading program in that rulemaking, evaluating historical state-level heat input variability over the period from 2000 through 2019. The updated analysis again resulted in a variability estimate of 21 percent. The EPA also considered shorter time periods for the updated analysis and found that the resulting variability estimates were not especially sensitive to the particular time period analyzed.[324] A further updated analysis for this rulemaking again results in a variability estimate of 21 percent for most states, and although the historical analysis indicates a higher percentage for the covered state with the smallest total heat input figures in this analysis—New Jersey—the EPA does not consider it appropriate to raise the minimum variability limit percentage beyond 21 percent for all other covered states based on the analytic results for one state, where small absolute heat input figures have resulted in a larger variability percentage.[325] (Moreover, because of the provision allowing a state's variability limit for a given control period to be higher than 21 percent if the state's actual heat input exceeds the heat input used to set the state's emissions budget by more than 21 percent, there is no need to set a minimum variability limit higher than 21 percent specifically for New Jersey.) Based on the consistent conclusions of these multiple analyses, the EPA is continuing to use 21 percent as the

[322] The total heat input amount used in computing each state's preset emissions budget for each control period from 2023 through 2029 is included in Appendix A of the Ozone Transport Policy Analysis Final Rule TSD at column I of the ''State 2023''–''State 2029'' worksheets.

[323] Briefly, the 21 percent variability limit was determined in the analysis by identifying, for all the states in the region covered by the ozone season NO_X trading program, and at a 95 percent confidence level, the maximum expected deviation in any state's total heat input for any single control period in the data sample from that state's trend-adjusted mean total heat input for all the control periods in the data sample. For details on the original variability analysis for 26 states over the 2000–2010 period, including a description of the methodology, see the Power Sector Variability Final Rule TSD from the CSAPR (EPA–HQ–OAR–2009–0491–4454), available in the docket for this rule.

[324] For the updated variability analysis for twelve states for the 2000–2019 period, *see* the Excel file ''Historical Variability in Heat Input 2000 to 2019.xls'', available in the docket for this rule.

[325] *See* the Excel document, ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

minimum value in the revised approach for establishing variability limits for all control periods under this rule.

The provisions of the final rule relating to assurance levels and variability limits are unchanged from proposal, with the exception that the provision establishing a higher variability limit for a state in a given control period where the state's actual heat input exceeds the heat input used in computing the state emissions budget for that control period by more than 21 percent will be implemented starting with the 2023 control period instead of the 2025 control period.

Comment: Some commenters supported the EPA's proposal to raise a state's variability limit above 21 percent for a given control period if the state's actual heat input for the control period was more than 121 percent of the historical heat input used to set the state's budget for that control period. These commenters agreed with the EPA that making this adjustment is consistent with the assurance provisions' purpose of strongly incentivizing each state to achieve its required emissions reductions within the state while also accounting for year-to-year variability in electric system operations.

One commenter stated that the EPA should not finalize the proposed revision to the variability limit provisions, claiming that by allowing sources in some states to increase utilization and heat input so as to exceed the state's budget by more than 21 percent in a given year, the adjustment would then cause the state's subsequent dynamically determined budgets to be higher, allowing greater emissions over time.

Response: The EPA disagrees with the comment advocating against finalization of the proposed change to the variability limit provisions. The Agency continues to view the proposed change as useful for accommodating instances where, because of electrical system operating needs, a state's actual total heat input in a control period exceeds the historical heat input used to set the state emissions budget for the control period, potentially causing increased emissions even when all EGUs in a state are achieving emissions rates consistent with the Step 3 emissions control stringency. Moreover, the EPA does not believe that the provision would lead to higher overall program-wide budgets. No extra allowances would be created by the increase in a state's variability limit, so with or without the adjustment, any allowances to cover the emissions in excess of the state's budget would still need to be obtained through acquisition of allowances issued to sources in other states or the use of banked allowances. Thus, to the extent that the change in the variability limit provisions facilitates shifting of generation from some states to other states, increased heat input in the first set of states would generally be offset by decreased heat input in the second set of states, such that any increases in future dynamic budgets for the first set of states would be offset by decreases in future dynamic budgets for the second set of states. In addition, the final rule's use of multiple years of historical heat input data to compute the dynamically-determined state budgets will moderate the effect of any single year's heat input on the dynamically-determined budgets for future control periods.

6. Annual Recalibration of Allowance Bank

As discussed in section VI.B.1.b of this document, the EPA is making two revisions to the Group 3 trading program designed to better maintain the Step 3 emissions control stringency over time. The first proposed revision, discussed in section VI.B.4 of this document, is to adopt a dynamic budget-setting methodology that will allow state emissions budgets in future years to reflect more accurate information about the composition and utilization of the EGU fleet. The second, complementary, revision is to recalibrate the bank of unused allowances each control period to prevent allowance surpluses from accumulating and adversely impacting the ability of the trading program in future control periods to maintain the Step 3 emissions control stringency.

As proposed and now finalized in this rule, the bank recalibration process will start with the 2024 control period, after the compliance process for the 2023 control period for all current and newly added states in the Group 3 trading program has been completed. The recalibration process for each control period will be carried out on or shortly after August 1 of that control period, two months after the compliance deadline for the previous control period, making the date of the first recalibration August 1, 2024. The recalibrations take place on August 1 each year because compliance for the previous control period would not be completed until after June 1. However, because data on the amounts of allowances held are publicly available and the total quantity of allowances needed for compliance for the previous control period will be known shortly after the end of that control period, sources and other market participants will be able to ascertain with reasonable accuracy shortly after the end of each control period what degree of recalibration to expect for the next control period, even if the recalibration would not actually be carried out until the following August. The EPA will make an estimate of the applicable calibration ratio for each control period publicly available no later than March 1 of the year of the control period for which the bank will be recalibrated.

Before undertaking a recalibration process each control period, the EPA will first determine whether the total amount of all banked Group 3 allowances from previous control periods held in all facility accounts and general accounts in the Allowance Management System exceeds the target bank amount. (For this purpose, no distinction will be made between banked Group 3 allowances issued from the state emissions budgets for previous control periods and banked Group 3 allowances issued through the conversion of previously banked Group 2 allowances.) If the total amount of banked Group 3 allowances does not exceed the target bank amount, the EPA will not carry out any recalibration for that control period. If the total amount of unused allowances does exceed the target bank amount, the EPA will determine for each account with holdings of banked Group 3 allowances the account-specific recalibrated amount of allowances, computed as the account's total holdings of banked Group 3 allowances immediately before the recalibration multiplied by the target bank amount and divided by the total amount of banked Group 3 allowances in all accounts, rounded up to the nearest allowance. Finally, the EPA will deduct from each account any banked Group 3 allowances exceeding the account's recalibrated amount of banked allowances.

As the target bank amount used in the recalibration process for each control period, the EPA will use an amount determined as a percentage of the sum of the state emissions budgets for the control period. For the control periods from 2024 through 2029, the target percentage will be 21 percent, which is the sum of the states' minimum variability limits.[326] For control periods in 2030 and later years, the target percentage will be 10.5 percent, or half of the sum of the states' minimum

[326] As discussed in section VI.B.5, an individual state's variability limit can be higher than 21 percent in a given control period if the state's actual heat input for that control period is more than 121 percent of the historical heat input used in computing the state emissions budget for the control period.

variability limits. In the proposal, the EPA cited two reasons for proposing the 10.5 percentage amount. First, in the transition from CSAPR to the CSAPR Update, where the EPA set a target bank amount 1.5 times the sum of the variability limits, and in the transition from the CSAPR Update to the Revised CSAPR Update, where the EPA set a target bank amount of 1.0 times the sum of the variability limits, in each case the initial bank proved larger than necessary, as total emissions of all sources in the program were less than the budgets. Second, an analysis of year-to-year variability of heat input for the region covered by this rule suggests that the regional heat input for an individual year can be expected to vary by up to 10.5 percent above or below the central trend with 95 percent confidence. This variability analysis is an application to the entire region of the variability analysis EPA has performed for individual states to establish the minimum variability limit of 21 percent for the states in the trading program.[327] When the analysis is performed at the regional level, the data show less year-to-year variation than when the analysis is performed at the individual state level. Within the trading program structure, it is reasonable to use variability analyzed at the level of individual states to set the variability limits, which apply at the level of individual states, while using variability analyzed at the level of the overall region to set a target level for a bank, which will apply at the level of the overall program.

In the final rule, in response to comments, the EPA has determined to maintain the 10.5 target percentage for the reasons discussed in previous paragraphs, but to defer application of this target percentage until the 2030 control period. For the control periods from 2024 through 2029, the EPA will instead use a target percentage of 21 percent. The reason for using a higher target percentage for the 2024–2029 control periods is to provide additional support for allowance market liquidity during these years, which both the EPA and commenters view as an important period of generating fleet transition for the power industry.

The annual bank recalibrations, at either ratio, are an important enhancement to the trading program that will help maintain the control stringency determined to be necessary to address states' good neighbor obligations for the 2015 ozone NAAQS over time. Moreover, the recalibrations are less complex than alternative approaches would be. For example, the NO_X Budget Trading Program established in the NO_X SIP Call also contained provisions designed to prevent excessive accumulations of banked allowances on program stringency, but those provisions—under the name ''progressive flow control''—introduced uncertainty as to whether banked allowances would be usable to offset one ton of emissions or less than one ton of emissions in the current control period. As a consequence of this uncertainty, in some control periods, allowances banked from earlier control periods traded at lower prices than allowances issued for the current control period.[328] The EPA considers the recalibration mechanism established in this rule to be simpler with less associated uncertainty. Following each bank recalibration, all allowances usable for compliance in the control period will have known, equal compliance values for the remainder of the control period and until the deadline for surrendering allowances after the control period.

Finally, the EPA observes that the recalibration mechanism is entirely consistent with the Agency's existing authority under 40 CFR 97.1006(c)(6) to ''terminate or limit the use and duration'' of any Group 3 allowance ''to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' The Administrator is determining that the recalibrations are both necessary and appropriate to ensure that the control stringency selected in this rulemaking is maintained and states' good neighbor obligations with respect to the 2015 ozone NAAQS are addressed. The recalibration process will complement the revised budget-setting process by preventing any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods. For further discussion of the reasons for bank recalibration, see section VI.B.1.b.ii of this document.

The bank recalibration mechanism finalized in this rule is unchanged from the proposal except for the final rule's adoption of a target percentage of 21 percent rather than 10.5 percent for the control periods from 2024 through 2029. The EPA's responses to comments on the bank recalibration mechanism are discussed in the remainder or this section and in section 5 of the *RTC* document. Further discussion of the reasons for adopting a higher target percentage for the 2024–2029 control periods is included in section VI.B.1.d of this document.

Comment: Some commenters acknowledged the EPA's authority to manage the quantities of allowances carried over from one control period to the next as banked allowances, including some commenters who as a policy matter did not support such an approach. Other commenters claimed that any removal from the program of allowances banked in earlier control periods would constitute an unlawful taking of property or would constitute unlawful overcontrol.

Response: The EPA disagrees with comments contending that the proposed bank recalibration provisions would be unlawful, either as asserted takings of property or as over-control for purposes of the Good Neighbor provision. With respect to the claim that removing allowances would constitute takings of property, the commenters misconstrue the nature of an allowance. The allowances used in the Group 3 trading program are created under the program's regulations, which expressly provide that the allowances are not property rights but are limited authorizations to emit NO_X in accordance with the provisions of the Group 3 trading program.[329] These provisions of the Group 3 trading program regulations have been in existence since the Revised CSAPR Update and were not reopened in this action. This approach of creating limited authorizations to engage in particular forms of conduct within a regulatory program extends back to the Acid Rain Program, where the approach was mandated by Congress, and has been followed by EPA in each subsequent allowance trading program for the electric power sector.[330] Moreover, as noted earlier in this section, the Group 3 trading program regulations provide the EPA

[327] See the Power Sector Variability Final Rule TSD from CSAPR, available at *https://www.epa.gov/csapr/power-sector-variability-final-rule-tsd* for a description of the methodology. Also see the Excel document ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

[328] For more discussion of the progressive flow control mechanism, as well as allowance price data showing a discounted value for banked allowances, see ''NO_X Budget Trading Program: 2005 Program Compliance and Environmental Results'' (September 2006) at 28–30, *https://www.epa.gov/sites/default/files/2015-08/documents/2005-nbp-compliance-report.pdf*.

[329] 40 CFR 97.1006(c)(6)–(7).

[330] *See, e.g.,* 42 U.S.C. 7651b(f) and 40 CFR 72.9(c)(6)–(7) (Acid Rain Program example); 40 CFR 97.6(c)(6)–(7) (Federal NO_X Budget Trading Program example); 40 CFR 97.106(c)(5)–(6) (CAIR NO_X Annual Trading Program example).

Administrator with the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act, and the Administrator is making such a determination in this rule.

The EPA also disagrees that bank recalibration would constitute overcontrol. The emissions that are permissible in a given control period consistent with the Step 3 control stringency are quantified in the state emissions budgets for the control period. Banked allowances from previous control periods are necessarily surplus to the state emissions budgets for the current control period. As noted in section VI.B.1, in an allowance trading program, banking provisions can serve several useful purposes, including continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. However, these useful purposes do *not* include allowing sources to plan to emit in excess of the Step 3 control stringency as represented by the state emissions budgets for the control period. Accordingly, in the overcontrol analysis discussed in section V.D.4, the EPA analyzed whether the emissions reductions necessary to meet the state emissions budgets without relying for compliance purposes on any allowances banked in earlier control periods would result in overcontrol and determined there would be no overcontrol. (That is, the modeling of the effects of the Group 3 emissions budgets in 2026 did not include an assumption that there would be any banked allowances.) Thus, even if the Agency had finalized regulatory provisions removing *all* banked allowances from the trading program between control periods—in contrast to the actual bank recalibration provisions, which permit substantial quantities of banked allowances to remain in the trading program—the information available to the Agency suggests such provisions would not constitute over-control. With respect to some commenters' assertions that bank recalibration would over-control by ''writing off'' emission reductions that may have gone beyond the reductions necessary to address the Good Neighbor provision or would make it more difficult to create surplus allowances in one control period to offset excess emissions in later control periods, EPA notes that the NAAQS apply continuously, and the possibility that the sources in a state may have done more than the minimum necessary to meet the state's Good Neighbor obligations in one control period does not create a right for the state to do less than is necessary to meet the state's Good Neighbor obligations in subsequent control periods.

Comment: Some commenters expressed concern that excessive quantities of banked allowances, like excessive quantities of budgeted allowances, can lead to lower allowance prices. The commenters observed that with lower allowance prices, some units would likely operate their controls less effectively, resulting in a greater likelihood that the emissions stringency found necessary in this rule would not be sustained. Other commenters expressed the view that other provisions of the rule, including more stringent state emissions budgets, the backstop daily NO_X emissions rate provisions, and the assurance provisions would be sufficient to incentivize EGUs to operate their controls effectively, making allowance bank recalibration superfluous for this purpose.

Response: The EPA agrees with the comments explaining that without bank recalibration, the quantities of banked allowances can grow, leading to lower allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency, and disagrees with the comments arguing that other rule provisions would make bank recalibration unnecessary. The suggestion that the assurance provisions can maintain program stringency regardless of allowance quantities ignores the fact that the emission levels consistent with the Group 3 control stringency in a given control period are the state emissions budgets, not the higher assurance levels. If the quantities of banked allowances in the program grow to the point where sources collectively can plan to emit above the collective state emissions budgets, then the trading program would be unable to ensure that the Group 3 control stringency is being achieved, even if emissions do not rise further than the assurance levels. Further, there are now examples from the Group 2 trading program of sources emitting in excess of the state-wide assurance levels, because a glut of banked allowances which was not prevented by the regulations for that trading program rendered even the three-to-one surrender ratio ineffective. Suggestions that the backstop emissions rate provisions can maintain program stringency regardless of the quantities of banked allowances are similarly mistaken, because rather than reducing overall emissions of all sources in the trading program, the backstop rate provisions are designed to ensure that the largest individual sources of potential emissions operate their controls consistently. If the quantities of banked allowances are allowed to grow to the point where sources collectively can plan to emit above the collective state emissions budgets, the backstop rate provisions would do nothing to constrain emissions from the sources not subject to the backstop rate.

With respect to the suggestion that state emissions budgets reflecting sufficient control stringency can avoid the need for bank recalibration, the EPA observes that the budget-setting and bank recalibration provisions in this rule are complements, not substitutes. If in a given year sources collectively emit against the collective state emissions budgets such that the ending allowance bank—that is, the allowances remaining after deduction of the allowances required for compliance—is less than the bank target amount, then the bank will not be recalibrated for the following control period. However, in the event that sources collectively emit against the collective state emissions budgets such that the ending allowance bank is above the bank target amount, then the recalibration provisions will ensure that the recalibrated allowance bank does not introduce an excessive overall quantity of allowances into the trading program for the following control period when combined with the state emissions budgets calculated for that control period. Without the recalibration provisions, the trading program would lack any mechanism for removing excess allowances that are inconsistent with maintaining the Step 3 emissions control stringency which the Step 4 trading program is designed to implement.

Comment: Some commenters claimed that the recalibration process itself would have undesirable consequences. First, some said that because bank recalibration would be executed partway through the control period, it would introduce uncertainty concerning the quantities of allowances each source would have available, impeding efforts to plan. Second, some commenters claimed that the prospect of bank recalibration would create counterproductive incentives for allowance holders. According to the commenters, allowances holders would be incentivized to ''use or lose'' their allowances (to reduce the number of allowances that would be removed from their accounts in the recalibration process), thereby causing increased emissions, or alternatively would be incentivized to refuse to sell allowances (to allow the holders to have more allowances after the next recalibration), thereby reducing allowance market liquidity.

Response: The EPA disagrees with these comments. As discussed previously in this section, the recalibration process has been scheduled for August 1 of each control period because compliance for the previous control period (and the associated allowance trading activities) would not be completed until after June 1. However, the information needed to project the degree of recalibration will be available by early November of the previous year, and the EPA will make an estimate publicly available no later than March 1, two months before the start of the control period. Further, at least 80 percent of the allowances for use in a given control period will be the allowances allocated from the state emissions budgets (with the recalibrated banked allowances from the prior control period comprising the remainder), and the emissions budgets and unit-level allocations amounts will be known approximately a year before the start of the control period.

The comments claiming that the introduction of a bank recalibration process would create incentives to ''use or lose'' allowances or to hoard allowances are not persuasive. By reducing the supply of allowances carried over from previous control periods, bank recalibration would tend to raise the price of allowances in the current control period, making it more cost-effective and therefore in sources' interest to further reduce their emissions than to increase their emissions. Higher allowance prices would also increase the cost of hoarding allowances just as higher fuel prices raise the cost of maintaining large fuel inventories. Moreover, the EPA expects that the prospect of having banked allowances recalibrated after the end of the control period is much more likely to *discourage* hoarding than to encourage it. Given the choice between holding an allowance which may be removed as part of an upcoming recalibration process or instead selling the allowance for cash, the sale option will become more attractive. By creating a ''sell or lose'' incentive for holders of surplus allowances, the recalibration process should increase allowance market liquidity. At the same time, by ensuring a banked allowance will always have some value for use in a future control period, the bank recalibration mechanism in this program will continue to incentivize early emissions reductions.

Comment: Turning to the level of the bank recalibration target, some commenters objected to the target bank percentage of 10.5 percent, saying that a larger bank would be needed to ensure that sufficient allowances would be available to enable sources to run as needed to provide reliable electricity service, particularly with the large year-to-year swings in budgets that the commenters anticipated could occur with dynamic budgets computed using a single rolling historical year and with anticipated growth in renewable generation. Some commenters recommended a target bank percentage of 21 percent. Some commenters stated that even if the overall quantity of allowances available for use was greater than the total amount of emissions, a larger bank of allowances would facilitate trading and promote greater allowance market liquidity, citing reports of high allowance prices in 2022.

Response: As discussed in sections VI.B.1.d and VI.B.4 and earlier in this section, the EPA does not agree with comments suggesting that annual bank recalibration in itself poses a risk to electric grid reliability. Nevertheless, the Agency has made several changes from proposal in the final rule designed to address concerns expressed about reliability by increasing compliance flexibility through the 2029 control period. These changes through the 2029 control period include the use of a target bank percentage of 21 percent and the promulgation of preset budgets that will serve as the state emissions budgets unless the dynamic budgets for the control periods are higher. In addition, to reduce year-to-year variability under the budget-setting methodology, dynamic budgets will be calculated using multiple years of historical heat input data instead of heat input data from a single year. The EPA views these changes as responsive to the principal reasons that commenters gave for their claims that the target bank percentage should be higher than 10.5 percent. Regarding the claim that a higher target bank percentage is needed because increased renewable generation makes the demand for fossil generation more variable, commenters did not provide evidence demonstrating that the overall quantities of fossil generation throughout the multi-state region covered by this rule—as opposed to the operating patterns of some individual units—are becoming more variable, and the Agency declines to make an adjustment for such a reason at this time.

With respect to the comments advocating for an even higher bank target percentage to facilitate trading and promote market liquidity, the Agency observes that any such advantage of larger allowance banks must be balanced with the disadvantages of excess allowance supply—specifically, reduced allowance prices, diminished incentives for sources to optimize control operation, and greater risk of failure to sustain the Step 3 control stringency. In the final rule, the EPA finds that a reasonable balance between these opposing considerations is struck by temporarily adopting a higher bank target percentage of 21 percent (consistent with the initial bank targets used in this rule and previous rules) and deferring implementation of the 10.5 percent target bank percentage identified by the Agency's analysis as a sustainable percentage in the longer term until the 2030 control period.

7. Unit-Specific Backstop Daily Emissions Rates

While the identified EGU emissions reductions in section V of this document (*i.e.,* the Step 3 emissions control stringency) are incentivized and secured primarily through the corresponding seasonal state emissions budgets (expressed as a seasonal tonnage limit for all covered EGUs within a state's borders) described earlier, the EPA is also incorporating a backstop daily emissions rate of 0.14 lb/mmBtu applied to coal-fired steam units serving generators with nameplate capacity greater than or equal to 100 MW in covered states, except circulating fluidized bed units. This is important for ensuring the elimination of significant contribution on a more consistent basis from the relevant sources and over each day of the ozone season.

Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) will apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding by more than 50 tons a daily average NO_X emissions rate of 0.14 lb/mmBtu. The daily average emissions rate provisions will apply to large coal-fired EGUs without existing SCR controls (except circulating fluidized bed units) starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. See Appendix A of the Ozone Transport Policy Analysis Final Rule

TSD for a list of coal-fired steam units serving generators larger than or equal to 100 MW in covered states for which the identified backstop emissions rate will apply.

For each unit subject to the backstop daily emissions rate provisions for a given control period, the amount of emissions subject to the 3-for-1 surrender ratio will be determined as follows, generally on an automated basis using the unit's data acquisition and handling system (DAHS) required under 40 CFR part 75. For each day of the control period where the unit's average emissions rate for that day was higher than 0.14 lb/mmBtu, the owner or operator will compute what the unit's reported emissions on that day would have been (given the unit's reported heat input for the day) at an emissions rate of 0.14 lb/mmBtu. The difference between the unit's emissions for the day as actually reported and the emissions that would have been reported if the unit's emissions rate was 0.14 lb/mmBtu is the unit's daily exceedance. The amount of emissions subject to the 3-for-1 surrender ratio for the control period is the sum of the unit's daily exceedances for all days of the control period minus 50 tons (but not less than zero).[331] All calculations will rely on the data monitored and reported for the unit in accordance with 40 CFR part 75.

The EGU NO_X Mitigation Strategies Final Rule TSD describes the methodology for deriving the 0.14 lb/mmBtu daily rate limit in more detail. The methodology is summarized as follows. First, consistent with stakeholders' focus on providing daily assurance of control operation, which is consistent with the 8-hour form of the 2015 ozone NAAQS and the tendency for ozone levels to spike on a diurnal cycle, the EPA determined that daily (as opposed to hourly or monthly) was an appropriate time metric for backstop emissions rate limits instituted to ensure operation of controls on high ozone days. The EPA derived the 0.14 lb/mmBtu daily rate limit by determining the particular level of a daily rate that would be comparable in stringency to the 0.08 lb/mmBtu seasonal emissions rate that the Agency has identified as reflecting SCR optimization at existing units.[332] The EPA first conducted an empirical exercise using reported daily emissions rate data from existing, SCR-controlled coal units that were emitting at or below 0.08 lb/mmBtu on a seasonal average basis. This seasonal rate reflects the average across a unit's range of varying daily rates reflecting different operation conditions. When the EPA examined the daily emissions rate pattern for these units considered to be optimizing their SCRs on a seasonal basis, the EPA observed that over 95 percent of the time, their daily rates were below 0.14 lb/mmBtu. In addition, for these units, less than 1 percent of their seasonal emissions would exceed this daily rate limit.

The EPA conducted this analysis to be consistent with the methodology developed in the 2014 1-hr SO_2 attainment area guidance for identifying ''comparably stringent'' emissions rates over varying time-periods.[333] Appendix C of that guidance describes a series of steps that involve: (1) compiling emissions data to reflect a distribution of emissions rates with various averaging times, (2) determining the 99th percentile of the average emissions values compiled in the previous step, and then (3) applying ''adjustment factors'' or ratios of the 99th percentile values to emissions rates to convert them (usually from a short-term rate to a longer-term rate). In this case, the EPA applied the methodology in reverse to convert a longer-term limit (the seasonal rate of 0.08 lb/mmBtu which was assumed to be equivalent to a 30-day rate of 0.08 lb/mmBtu for purposes of this comparison of rates across averaging times) to a comparably stringent short-term limit (a daily rate of 0.14 lb/mmBtu).

The inclusion of a 50-ton threshold for emissions exceeding the backstop daily emissions rate before the 3-for-1 surrender applies is a change from the proposal. As discussed in section VI.B.1.d of this document, the EPA made this change in response to comments concerning the possibility that the 3-for-1 surrender ratio could otherwise have applied to emissions outside an EGU operator's control, with the most important example being the emissions during unit startup before SCR equipment can be brought into service, and to a lesser extent the emissions during unit shutdown. The analysis used by the EPA to derive the 50-ton threshold is described in detail in the Ozone Transport Policy Analysis Final Rule TSD. Briefly, for a set of 164 SCR-equipped units with seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu in 2021, the EPA evaluated the total amounts of emissions that would have been determined to exceed a daily average emissions rate of 0.14 lb/mmBtu in the 2021 and 2022 ozone seasons. In the 2021 ozone season, only 572 tons out of these units' total emissions of 60,350 tons, or 0.9 percent, would have been considered exceedances, with an average exceedance per unit of less than 4 tons. The highest amount for any of the 164 individual units in either ozone season was 48 tons. Based on this analysis, the EPA concludes that adding a 50-ton threshold to the backstop daily emissions rate provisions will ensure that substantially all emissions outside the control of an SCR-equipped unit's operator will not be subject to the 3-for-1 surrender ratio. Because there is no reason to expect the range of emissions during conditions when SCR controls cannot be operated to differ between SCR-equipped units and units without SCR, inclusion of the 50-ton threshold effectively prevents application of the 3-for-1 ratio to emissions during startup and shutdown by units without SCR as well.

At the same time, the EPA believes the 50-ton threshold is not large enough to eliminate the intended incentive to achieve emissions rates consistent with good SCR performance under conditions other than startup and shutdown. For a set of 124 SCR-equipped units with seasonal average NO_X emissions rates above 0.08 lb/mmBtu, the total amount of emissions exceeding a daily average emissions rate of 0.14 lb/mmBtu in the 2021 ozone season was 18,629 tons. Of this total amount, 15,374 tons would have been in excess of the 50-ton thresholds for the various units, indicating that even after application of the threshold, the 3-for-1 surrender ratio would have applied to over 80 percent of the daily exceedance amounts.

The backstop daily NO_X emissions rate provisions finalized in this rule are unchanged from the proposal except for the inclusion of a 50-ton threshold for emissions exceeding the backstop emissions rate before the 3-for-1 surrender ratio applies and the deferral of the application of the provisions to units without existing SCR controls

[331] In the regulatory text at 40 CFR 97.1024 defining the total quantity of allowances that must be surrendered for a source's emissions in a control period, these amounts of emissions for all the units at the source are subject to a requirement to surrender two extra allowances per ton in addition to the usual 1-for-1 allowance surrender requirement, yielding a total surrender ratio of 3-for-1 for emissions over the 50-ton threshold.

[332] *See* page 24 of ''Guidance for 1-hour SO_2 Nonattainment Area SIP Submission'' at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.* ''A limit based on the 30-day average of emissions, for example, at a particular level is likely to be a less stringent limit than a 1-hour limit at the same level 1 since the control level needed to meet a 1-hour limit every hour is likely to be greater than the control level needed to achieve the same limit on a 30-day average basis.''

[333] *See* Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions available at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.*

until the 2030 control period or, if earlier, the second control period in which new SCR controls are operated at a unit. The EPA's responses to comments on the backstop daily NO_X emissions rate provisions, including the reasons for these changes, are discussed in the remainder of this section and in section 5 of the *RTC* document.

Comment: Some commenters strongly supported the backstop daily emissions rate provisions, noting their benefit to downwind receptors on potential nonattainment days, their benefit to neighboring communities, and evidence of deterioration in SCR performance in the absence of such provisions. Other commenters stated that the backstop daily emissions rate provisions are unnecessary, either because SCR-equipped EGUs would already be sufficiently incentivized to operate and optimize their controls by the stringency of the state emissions budgets and the resulting allowance prices or because most SCR-equipped EGUs are already required to operate and optimize their SCRs by conditions in their operating permits. Some commenters cited previous EPA analyses showing that it is unusual for SCR-equipped units to turn off their SCRs only on high electricity demand days (HEDD).

Commenters suggested diverse possible changes to the types of EGUs that would be covered by the backstop daily emissions rate provisions. Some commenters stated that the provisions should apply to all EGUs or to all SCR-equipped EGUs, including non-coal-fired units. Other commenters stated that exemptions should be provided for units operating at capacity factors below 10 percent or for emissions during emergencies.

Some commenters stated that implementation of the backstop daily emissions rate provisions would cause unintended and counterproductive consequences. Some of these commenters claimed that by requiring the surrender of extra allowances, the backstop emissions rate provisions would create shortages of allowances for the program overall. Other commenters claimed that the disincentives to operate units subject to the backstop emissions rate provisions would cause load to shift to higher-emitting generators not covered by the trading program (such as sources in states outside the program's geographic region, EGUs smaller than 25 MW, and sources considered demand-side resources, including end-user-sited diesel generator units), potentially resulting in higher overall emissions.

Response: The EPA agrees that backstop daily emissions rate provisions should be implemented and disagrees with comments suggesting that the need for the backstop daily emissions rate provisions is contradicted by previous EPA analyses or is already adequately addressed by other provisions of this rule or other legal requirements. As discussed in sections V.D.1 and VI.B.1.c of this document, the EPA has determined that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs is appropriate. There are several important differences between this rule and previous actions addressing interstate ozone transport where the Agency did not include such provisions. First, this rule constitutes a full remedy, unlike some prior actions. Second, this rule is the first rule in which the EPA is addressing good neighbor obligations with respect to the more protective 2015 ozone NAAQS. Third, the EPA has examined the most recent data over a broader geographic and temporal footprint specific to the coverage of this rule, and it illustrates a greater degree of SCR performance erosion than in the prior years in which EPA conducted such analysis. Fourth, nonattainment and maintenance for this NAAQS are projected to persist well into the future in EPA's baseline, making enhancements and safeguards such as the backstop daily emissions rate provisions essential for securing elimination of significant contribution in future periods for which fleet configuration is inherently more uncertain.

With respect to claims that inclusion of the backstop daily emissions rate provisions is contradicted by the EPA's earlier analyses concerning SCR operational changes specific to high electricity demand days, the EPA disagrees. Historical data reported to the EPA show that multiple SCR-equipped units across the states covered by this action have chosen not to operate their SCRs, or to operate them at materially less than their full removal capability, for entire ozone seasons. The apparent infrequency of one type of behavior—*i.e.,* instances of units running their controls on most days but turning the controls off specifically on high electricity demand days—does not contradict the evidence concerning another type of behavior—*i.e.,* non-operation or suboptimal operation of controls for entire ozone seasons. The evidence from previous trading programs demonstrates that reliance solely on the incentives created by allowance prices and corresponding static state emissions budgets has been insufficient to cause all SCR-equipped units to operate and optimize their controls for entire ozone seasons.

The EPA acknowledges that some SCR-equipped units are likely already subject to other legal requirements calling for their SCR controls to be operated and optimized such that their seasonal average NO_X emissions rates will generally not exceed 0.08 lb/mmBtu (the level of seasonal SCR performance that the EPA used to derive the equivalent 0.14 lb/mmBtu level of daily SCR performance for the backstop daily NO_X emissions rate). However, commenters do not claim, and the EPA does not believe, that *all* SCR-equipped units are subject to other legal requirements calling for an equivalent degree of SCR operation and optimization. In the context of a multi-state trading program, it is more efficient and equitable, and far more transparent, for the EPA to establish rule provisions uniformly incentivizing all large coal-fired EGUs to install and operate SCR controls than to attempt to establish differentiated requirements for various units according to the EPA's analysis of the effectiveness of their pre-existing permit conditions. Further, to the extent that a given unit's permits already require SCR performance that would meet the backstop emissions rate established in this rule, or to the extent that allowance prices would incentivize the unit to operate the SCR anyway, the EPA expects that the backstop daily emissions rate provisions (as finalized with a 50-ton threshold to address emissions outside an EGU's control before the 3-for-1 surrender ratio applies) will cause no incremental cost for the unit.

The EPA disagrees with the suggested changes to applicability of the backstop emissions rate provisions. With respect to the comments advocating broader coverage, the EPA discusses its reasons for applying the provisions only to coal-fired EGUs in section VI.B.1.c of this document, including the fact that operation of SCR controls is a well-established practice among the best performing coal-fired boilers but not for non-coal-fired units.[334] The comments indicate a preference for a less flexible trading program design than the EPA has found appropriate but do not demonstrate that EPA's decision to allow greater flexibility is either impermissible or unreasonable; our reasoning in this regard is further explained in section VI.B.1.c.i of this

[334] Nationwide and among operating units in 2021, EPA identified the best performing quartile (*i.e.,* lowest ozone season emissions rate) of coal-fired EGU boilers (excluding CFB units). Nearly 100 percent of these units (159 of 160 units) were equipped with SCR controls.

document. With respect to the comments advocating narrower coverage, the commenters have provided no information indicating that the sources for which exemptions are sought could not comply with the provisions, including through the surrender of additional allowances if necessary. The EPA notes that emissions from coal-fired units operating at low capacity factors may be concentrated around days of high electricity demand when incentives to minimize such emissions may be most helpful in mitigating downwind air quality problems. The EPA also notes that to the extent the comments are intended to support exemptions for units without existing SCR controls, the final rule defers application of the backstop emissions rate provisions to such units until the 2030 control period, providing additional flexibility to develop alternatives to the use of such units if the owners choose not to equip them with SCR controls.

Finally, the EPA also disagrees with the comments asserting that the backstop emissions rate provisions would cause unintended and counterproductive consequences. With respect to units already equipped with SCR controls, the EPA expects that by far the most important effect of the provisions will be to incentivize the units to operate and optimize their controls. The EPA sees no basis for speculation that such units would choose to operate in a manner that would result in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio or in generation being shifted to sources outside the trading program. The results of the EPA's modeling of benefits and costs of the rule show little leakage of emissions to non-covered sources, and commenters have presented no analysis to the contrary. For instance, as shown in Table 4.6 of the *RIA,* non-covered state ozone season NO_X emissions increased on average by 1 percent over the 2023–2030 time period between the base and final rule scenarios, while covered state emissions fell by 14 percent on average over the same period. With respect to units without existing SCR controls, the EPA expects the backstop emissions rate provisions, when they would take effect for such units, to provide a strong incentive against extensive operation (unless and until such controls are installed), again not resulting in large amounts of emissions becoming subject to the 3-for-1 allowance surrender ratio.

Comment: For units with existing SCR controls, the aspect of the backstop daily emissions rate provisions that received the most attention in comments was how emissions outside the operator's control should be treated. Multiple commenters expressed concern that the backstop daily emissions rate would be exceeded on days when the SCR equipment cannot be operated for all or a portion of the day. The most commonly cited example of a situation where SCR equipment cannot be operated was unit startups, although some commenters also mentioned unit shutdowns, boiler or emissions control malfunctions, and unit maintenance or tests. The commenters expressed the view that emissions that cannot be controlled by SCR equipment should be exempted from the backstop emissions rate provisions and suggested a variety of approaches for implementing an exemption.

Some commenters also stated that the backstop emissions rate provisions would not sufficiently accommodate sustained low-load operation, such as where an SCR-equipped unit operates for extended periods at a load level too low to permit SCR operation so that the unit is ready to ramp up to higher load levels in less time than would be required for a startup. The commenters suggested that implementation of a backstop daily rate would reduce the ability to operate the units in this manner, generally reducing system flexibility. Some noted that the need for flexibility of this nature is increasing because of the rapid growth in intermittent renewable generation.

Additional comments on the backstop daily emissions rate provisions for units with existing SCR controls addressed the level of the daily emissions rate and the implementation timing. With respect to the rate level, various commenters suggested rates from 0.08 to 0.20 lb/mmBtu. With respect to implementation timing, some commenters stated that because immediate compliance was possible, the good neighbor provision required implementation as of the 2023 control period rather than the 2024 control period as proposed. Other commenters expressed the view that units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls. Some owners of SCR-equipped EGUs that exhaust to stacks shared with EGUs without SCR suggested that their particular units with existing SCR controls should not be required to comply with the backstop emissions rate provisions earlier than units without existing SCR controls in order to avoid the cost of upgrading their emissions monitoring equipment.

Response: With respect to the topic of emissions outside an operator's control, as a general matter the EPA agrees that the backstop daily emissions rate provisions are intended to incentivize good SCR operation and that it was not the Agency's intent to apply a higher surrender ratio to emissions that are truly unavoidable, such as emissions occurring before an operator could reasonably initialize SCR operation when a unit is started up. As explained elsewhere in this section, the EPA selected the level of the backstop rate based on analysis of 2021 emissions data showing that for SCR-equipped coal-fired units achieving seasonal average NO_X emissions rates at or below 0.08 lb/mmBtu, more than 99 percent of the units' emissions would fall below a backstop daily emissions rate of 0.14 lb/mmBtu. In response to the comments summarized previously, the EPA has further analyzed 2021 and 2022 emissions data to determine what if any modifications to the proposal might be appropriate to limit the imposition of a 3-to-1 allowance surrender requirement for emissions caused by circumstances outside an operator's control while preserving the intended incentive to operate and optimize SCR controls whenever possible. The analysis showed that for the same set of units achieving seasonal average emissions rates at or below 0.08 lb/mmBtu, the highest total amount of emissions exceeding the backstop daily emissions rate in either the 2021 or 2022 control period for any unit was 48 tons. The Agency views this amount as a reasonable upper bound on the quantity of emissions that might contribute to an exceedance of the backstop emissions rate arising from circumstances outside an operator's control for any coal-fired unit, not just the well-controlled units in the data set analyzed, because the amount generally encompasses all of a unit's emissions occurring in hours when an SCR could not be operated over an ozone season.

Based on this analysis, the backstop daily emissions rate provisions in this final rule exclude the first 50 tons of a unit's emissions in a given control period exceeding the backstop daily emissions rate from incremental allowance surrender requirements. The EPA finds that establishing a threshold of this nature will provide an appropriate maximum exclusion to all coal-fired units for unavoidable emissions caused by circumstances outside the operator's control while maintaining the incentives for less well-controlled units to improve their emissions performance on all days of the ozone season. Well-controlled units will likely have no emissions over the threshold that will be subject to incremental allowance surrender requirements, while for SCR-equipped units not already achieving a seasonal average emissions rates sufficiently low to routinely operate at daily average emissions rates of 0.14 lb/mmBtu or less, the incentive to reduce daily emissions rates will remain in place, because the 50-ton threshold is not expected to encompass all emissions exceeding the backstop daily emissions rate for such units. In contrast to more complicated exceptions suggested by commenters, the 50-ton threshold can be easily integrated into the overall trading program structure with minimal additional recordkeeping and reporting requirements.

With respect to the comments claiming that the inability of some SCR-equipped units to operate their SCR controls at sustained low load levels likewise merits alteration of the backstop daily emissions rate provisions, the EPA disagrees. There is no dispute concerning the technical need for a unit to attain and maintain a certain range of exhaust gas temperatures at the SCR inlet in order to achieve optimal SCR performance and no dispute concerning the general relationship between a unit's load level in a given hour and its ability to attain and maintain that exhaust gas temperature range in that hour. However, the EPA is also aware that at least in some cases, units whose role in the integrated electric system currently calls for them to operate at low load levels for sustained periods (such as overnight) in fact may be able to operate at slightly higher load levels that would accommodate SCR operation during those periods and still meet the needs of the integrated electric system, thereby avoiding operation of the unit for sustained periods with the SCR out of service. Figure B.5 in the EGU NO_X Mitigation Strategies Final Rule TSD illustrates this opportunity using data reported for the 2021 and 2022 ozone seasons by a large SCR-equipped EGU in Pennsylvania. In both ozone seasons, the unit often cycled daily between its maximum load of approximately 900 MW during the daytime and a lower load level overnight, and in both ozone seasons the unit's typical daytime emissions rate was between 0.05 and 0.07 lb/mmBtu. However, while in the 2021 ozone season, the unit cycled down to a load level of approximately 440 MW overnight and did not operate its SCR, in the 2022 ozone season, when allowance prices were considerably higher, the unit cycled down to a load level of approximately 540 MW overnight and did operate its SCR. Despite the higher nighttime generation levels, the result was a decrease of roughly 50 percent in the unit's seasonal average NO_X emissions rate, from approximately 0.14 lb/mmBtu to approximately 0.07 lb/mmBtu, and a comparable reduction in NO_X mass emissions. This unit is not uniquely situated; operating data for several other large SCR-equipped EGUs in Pennsylvania show the same past pattern of cycling down to low load levels at which the SCR controls cannot be operated, and these other units have similar opportunities to cycle down to somewhat higher load levels (necessarily subject to the needs and constraints of the integrated electric system) at which their SCR controls can be operated.[335] No commenter has submitted data to the contrary. Furthermore, this example demonstrates the need for this rule's backstop emissions rate provision, which (had it been in place) would have motivated this facility to operate its SCR overnight during the 2021 ozone season when the prevailing allowance price provided an insufficient incentive to do so.

The EPA disagrees with the comments advocating for a backstop daily emissions rate lower or higher than 0.14 lb/mmBtu. In general, these comments simply represent disagreements with the EPA's conclusions regarding the identification of required emissions reductions under this rule, as reflected in part by the EPA's conclusion that a seasonal average emissions rate of 0.08 lb/mmBtu reasonably reflects the seasonal average emissions rate achievable through optimization of controls by existing SCR-equipped units that are not already achieving a lower seasonal average emissions rate. Comments concerning the selection of the 0.08 lb/mmBtu seasonal average emissions rate are addressed in section V of this document. Commenters did not challenge the EPA's analysis identifying a daily emissions rate of 0.14 lb/mmBtu as comparable in stringency to a seasonal average emissions rate of 0.08 lb/mmBtu (see further discussion elsewhere in this section).

The EPA also disagrees with the comments stating that the backstop daily emissions rate provisions should apply to units with existing SCR controls starting in a control period earlier or later than the 2024 control period. The EPA does not consider implementation of the provisions in the 2023 control period feasible because it is currently unknown whether the necessary updates to the emissions recordkeeping and reporting software for all the affected sources could be completed and tested before July 30, 2023, which is the first quarterly reporting deadline for the 2023 control period. Moreover, as discussed in section VI.B.1.c.i of this document, implementing the requirements starting in 2024 will provide a window for EGUs to improve the consistency of SCR operation or in some cases to optionally install additional emissions monitoring equipment. As for the suggestion that implementation timing of the backstop daily emissions rate provisions for units with existing SCR controls should be synchronized with the later implementation timing for units without existing SCR controls, the EPA is not persuaded that there is any inequity in implementing provisions intended to incentivize operation of SCR controls first at sources that already have such controls and later at sources that do not already have such controls, allowing time for the latter sources to install the controls. In any event, in this instance, where some upwind sources have an immediate and highly cost-effective option for controlling their emissions, the statutory requirement for significant contribution to be eliminated as expeditiously as practicable so as to provide downwind states with the protection intended by the Good Neighbor provision overrides these sources' claim of inequity relative to sources whose emissions control options would take longer and have higher cost. We conclude that the backstop daily emissions rate is an important aspect of the elimination of significant contribution and should be applied at the relevant units. It is only out of recognition of unique circumstances associated with facilitating power-sector transition as identified by commenters, that we defer the application of the rate for the minority of units that have not yet installed SCR controls.

Finally, with respect to the SCR-equipped units that share common stacks with units that do not have SCR, the EPA disagrees that monitoring cost considerations merit a later implementation date for the backstop daily emissions rate provisions. As discussed in section VI.B.10 of this document, five plants with this configuration are covered by the rule (one of which has announced plans to retire in 2023). Under this rule, as proposed, the owner of a plant with this

[335] See the spreadsheet ''Conemaugh and Keystone unit 2021 to 2022 hourly ozone season data'' in the docket.

configuration can choose between either upgrading the plant's monitoring systems so as to obtain unit-specific NO_X emissions rate data for each unit subject to the backstop daily emissions rate or else using the NO_X emissions rate data from the common stack, recognizing that the common stack emissions rate would generally be biased upwards relative to the emissions rate that could be reported for the SCR-equipped unit if that unit's emissions were monitored separately. Commenters have suggested a third option of a temporary exemption from the backstop emissions rate to avoid the cost of upgrading their monitoring systems. With the timing for implementation of the backstop emissions rate provisions for currently uncontrolled units in the proposal, the temporary exemption for the SCR-equipped units would have been in place for three control periods, from 2024 through 2026. With the final rule's deferral of the implementation of the backstop emissions rate provisions for the uncontrolled units for up to three years, the suggested temporary exemption for the SCR-equipped units would be in effect for up to six control periods, from 2024 through 2029. The EPA does not consider it reasonable to allow these SCR-equipped units an exemption from the backstop rate provisions for six years to avoid the cost of upgrading their monitoring systems, particularly given that the additional costs of monitoring at the individual-unit level are already borne by the large majority of other plants and the rule already provides these plants with an alternative to the monitoring system upgrades, if desired, by allowing the plants to use the emissions rate data from the common stack.[336]

Comment: With respect to units without existing SCRs, some commenters viewed the backstop daily emissions rate provisions as likely to make units without SCR altogether unwilling or unable to operate and characterized the provisions as a mandate for such units to install such controls or retire as of the control period when the provisions are implemented. Other commenters acknowledged that the provisions are not actually hard limits but stated that the higher allowance surrender ratio for emissions in excess of the backstop daily rate would nevertheless reduce the ability of such units to operate as needed to back up intermittent renewable generation. Some commenters claimed that inclusion of the backstop daily emissions rate provisions would substantially eliminate the potential benefits of allowance trading, because all units would have to meet the same emissions rate.

Some commenters stated that the proposed application of the daily backstop emissions rate provisions in the 2027 control period in some cases would occur only slightly before the units' otherwise planned retirement dates, and that short-term reliability considerations could create the need to make substantial investments in new controls at the units, which in turn could result in deferral of the units' retirement plans. In the proposal, the EPA requested comment on the possibility of deferring the application of the backstop emissions rate provisions to units without existing SCR controls until the 2029 control period if the owners provided the EPA with information indicating with sufficient certainty that the units would retire by the end of 2028. Commenters in favor of this concept suggested longer deferral periods, ranging from 2029 through 2032, and some also suggested that the EPA should simultaneously enlarge the emissions budgets to provide more allowances for units subject to the deferred requirement. Other commenters opposed any deferral of the applicability of the backstop rate provisions.

Response: The EPA disagrees that implementation of the backstop daily emissions rate provisions for EGUs without existing SCR controls constitutes a mandate for such units to install controls or retire but agrees that, as intended, the provisions would create strong incentives to minimize operation of the units unless and until controls are installed, and further agrees that in some instances retirement and replacement may be a more economically attractive option for the unit's customers and/or owners than installation of new controls. The EPA's rationale for determining at Step 3 that the control stringency required to address states' good neighbor obligations includes achievement of emissions rates consistent with good SCR performance at all large coal-fired EGUs (other than circulating fluidized bed boilers) is discussed in section V.D.1 of this document, and the EPA's rationale for determining at Step 4 that the trading program should include strong unit-level incentives to implement these controls is discussed in section VI.B.1.c. of this document. As noted in section VI.B.1.c of this document, the backstop daily emissions rate provisions are structured as incremental allowance surrender requirements rather than as directly enforceable emissions limits to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. The EPA appreciates that, in comparison to previous transport rules using a trading program mechanism for the power sector, the degree of flexibility available under this rule is reduced both by the greater stringency of the overall emissions reduction requirements, which leave less room to accommodate emissions from high-emitting units such as uncontrolled coal-fired units, and by the backstop daily emissions rate provisions. However, the EPA maintains that the trading program structure still is significantly more flexible than an array of directly enforceable emissions limits imposed on all EGUs or even on all coal-fired EGUs, and the comments do not show otherwise.

With respect to the comments concerning the timing for application of the backstop daily emissions rate provisions to EGUs without existing SCR controls, in the final rule the provisions will apply to these units starting with the second control period in which newly installed SCR controls are operational at the unit, but not later than the 2030 control period. As discussed in section VI.B.1.d of this document, the purpose of this change from the proposal is to address concerns expressed by RTOs and other commenters that application of the backstop daily NO_X emissions rate to EGUs without existing SCR controls starting in the 2027 control period would provide insufficient time for planning and investments needed to facilitate the unit retirements they viewed as likely to be a preferred compliance pathway for some owners. The EPA recognizes that retrofitting new emissions controls on aging coal-fired EGUs may be less environmentally efficient than the alternative of retirement and replacement, which could yield lower cumulative emissions of NO_X and multiple other pollutants over time. The EPA also recognizes that several coal-fired EGUs have already been considering retirement in 2028 (or earlier) under compliance pathways available under the Clean Water Act effluent guidelines[337] and the coal combustion residuals rule under the

[336] The owner of one of the five plants with common stacks submitted comments stating that no location in the plant's ductwork could meet the criteria for a unit-specific monitoring location. As discussed in section VI.B.10 of this document, EPA staff have reviewed the comment and do not believe the commenter has provided sufficient information to reach such a conclusion.

[337] See 40 CFR 423.11(w).

Resource Conservation and Recovery Act.[338] The year 2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas.[339] In addition, other regulatory actions at the state or Federal level are being or recently have been proposed. This includes among other things a proposed revision to the PM NAAQS for which transport SIPs would be due later in the 2020s. We understand that EGUs may wish to take the entire regulatory and market landscape into account when deciding whether to invest in SCR or pursue other NO_X reduction strategies. To facilitate a unit-level compliance alternative under this rule that maintains the NO_X reductions corresponding to SCR-level emissions control performance required by the state budgets from 2026 forward and that is potentially superior both economically and environmentally across multiple regulatory programs than installation of new, capital-intensive, post-combustion controls, the EPA is providing the fleet more flexibility in how to achieve those emissions reductions in the years through 2029. Relatedly, the deferral of the application of the backstop emissions rate provisions to uncontrolled units also addresses commenters' concerns that the provisions otherwise would reduce the ability of uncontrolled units to operate as needed to back up intermittent renewable generation (subject of course to the allowance-holding requirements to cover emissions). The deferral addresses this concern directly for the period through 2029, by eliminating application of the backstop provisions to uncontrolled EGUs through this period, and also indirectly after 2029, by ensuring the availability of sufficient time for owners and operators to complete other investments that may be needed to back up renewable generation after that point.

The EPA disagrees with the comments stating that application of the backstop daily emissions rate provisions to uncontrolled units should not be deferred and also disagrees with the comments stating that deferral should be accompanied by increases in the state emissions budgets reflecting higher assumed emissions rates for these units. The responses to these two comments are related. This rule complies with the mandate for the EPA to address good neighbor obligations as expeditiously as practicable and is based on a demonstration that emissions reductions commensurate with the overall emissions control strategy at Step 3 can be achieved beginning in the 2027 ozone season (following a two-year phase in of emissions reductions associated with installation of SCR retrofits). In the *RIA,* we demonstrate that EGUs will have multiple pathways to meeting the state budgets even if they choose not to install the SCR controls—thus no relaxation in the stringency of these budgets has been demonstrated to be warranted based on feasibility, necessity, or impossibility. The EGU economic modeling discussed in the *RIA* illustrates that many sources identified as currently having SCR retrofit potential elect not to install a SCR, and those that do retrofit SCR make no such installation until 2030. Yet, the fleet is able to comply with 2026 state emissions budgets (whose emissions reductions are premised in large part on assumed SCR retrofits) through reduced utilization (many of these units are projected to retire, and thus reduce emissions). While these changes in coal fleet utilization are not required or imposed through the EPA's state emissions budgets, they are projected to be an economic preference for a substantial portion of the unretrofitted fleet owing to future market and policy conditions. If sources do ultimately elect this pathway, then compliance will occur with significantly less demand on SCR retrofit labor and material markets than assumed at Step 3. The daily emissions rates are a backstop to the broader emissions reduction requirements, which we view as an important and necessary component to the elimination of significant contribution. But we also recognize that the objectives to be accomplished by the backstop must be balanced with larger economic and environmental conditions facing EGUs for which a deferral of the backstop rate ultimately is the most reasonable approach given these competing concerns. *See Wisconsin,* 938 F.3d at 320 (''EPA, though, possesses a measure of latitude in defining which upwind contribution 'amounts' count as 'significant[ ]' and thus must be abated.''). As noted in section VI.B.1.d of this document, the EPA finds that as long as state emissions budgets continue to reflect the required degree of emissions reductions at least for an interim period until the backstop rate would apply more uniformly, deferral of the backstop rate requirement for uncontrolled units in recognition of the transition period identified by commenters can be justified on the basis of the greater long-term environmental benefits obtained through greater compliance flexibility.

8. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

As emphasized by the D.C. Circuit in its decision invalidating CAIR, under the CAA's good neighbor provision, emissions ''within the State'' that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state must be prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). The CAIR trading programs contained no provisions limiting the degree to which a state could rely on net purchased allowances as a substitute for making in-state emissions reductions, an omission which the court found was inconsistent with the requirements of the good neighbor provision. *Id.* In response to that holding, the EPA established the CSAPR trading programs' assurance provisions to ensure that, in the context of a flexible trading program, the emissions reductions required under the good neighbor provision in fact will take place within the state. The EPA believes the assurance provisions have generally been successful in achieving that objective, as evidenced by the fact that since the assurance provisions took effect in 2017, out of the nearly 300 instances where a given state's compliance with the assurance provisions of a given CSAPR trading program for a given control period has been assessed, a state's collective emissions have exceeded the applicable assurance level only four times.

Unfortunately, the EPA also recognizes that the assurance provisions' very good historical compliance record is not good enough. The four past exceedances all occurred under the Group 2 trading program: sources in Mississippi collectively exceeded their applicable assurance levels in the 2019 and 2020 control periods, and sources in Missouri collectively exceeded their applicable assurance levels in the 2020 and 2021 control periods.[340] Both of the exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped,

[338] See 40 CFR 257.103(b).

[339] See 40 CFR 51.308(f).

[340] Information on the assurance level exceedances in the 2019, 2020, and 2021 control periods is available in the final notices concerning EPA's administration of the assurance provisions for those control periods. 85 FR 53364 (August 28, 2020); 86 FR 52674 (September 22, 2021); 87 FR 57695 (September 21, 2022).

coal-fired steam units had not chosen to idle the units' controls and rely instead on net out-of-state purchased allowances. The exceedances were large, and ample quantities of allowances to cover the resulting 3-for-1 allowance surrender requirements were purchased in advance, suggesting that the assurance level exceedances may have been anticipated as a possibility. In the case of the Mississippi exceedances, the exceedances were smaller, operational variability (manifesting as increased heat input) appears to have been a material contributing factor, and the EPA has not concluded that the owners and operators anticipated the exceedances. However, an additional contributing factor was the fact that several large, gas-fired steam units without SCR controls emitted NO_X at average rates much higher than the average emissions rates the same units had achieved in previous control periods. In short, while the Missouri exceedances appear far more significant, the EPA's analysis indicates that all four past exceedances could have been avoided if the units most responsible had achieved emissions rates more comparable to the same units' previous performance. In the EPA's view, the operation of the Missouri units in particular—although not prohibited by the current regulatory requirements—cannot be reconciled with the statutory requirements of the good neighbor provision. The fact that such operation is not prohibited by the current regulations therefore indicates a deficiency in the current regulatory requirements.

To correct the deficiency in the regulatory requirements, the EPA in this rulemaking is revising the Group 3 trading program regulations to establish an additional emissions limitation to more effectively deter avoidable assurance level exceedances starting with the 2024 control period. Because the pollutant involved is ozone season NO_X and the particular sources for which deterrence is most needed are located in states that are transitioning from the Group 2 trading program to the Group 3 trading program, the EPA is promulgating the strengthening provisions as revisions to the Group 3 trading program regulations rather than the Group 2 trading program regulations.[341]

The two historical emissions-related compliance requirements in the Group 3 trading program regulations are both structured in the form of requirements to hold allowances. The first requirement applies at the source level: specifically, at the compliance deadline after each control period, the owners and operators of each source covered by the program must surrender a quantity of allowances that is determined based on the emissions from the units at the source during the control period. The second requirement applies at the designated representative level (which typically is the owner or operator level): if the state's sources collectively emit in excess of the state's assurance level, the owners and operators of each set of sources determined to have contributed to the exceedance must surrender an additional quantity of allowances. As long as a source's owners and operators comply with these two allowance surrender requirements (and meet certain other requirements not related to the amounts of the sources' emissions), they are in compliance with the program.

In light of the operation of the Missouri sources, the EPA is doubtful that strengthening the assurance provisions by increasing allowance surrender requirements at the unit, source, or designated representative level would create a sufficient deterrent. Accordingly, the EPA is instead adding a new, unit-level emissions limitation structured as a prohibition to emit NO_X in excess of a defined amount. A violation of the prohibition will not trigger additional allowance surrender requirements beyond the surrender requirements that would otherwise apply, but will trigger the possible application of the CAA's enforcement authorities. The new emissions limitation will be in addition to, not in lieu of, the other requirements of the Group 3 trading program. This point is being made explicit by relabeling the source-level allowance holding requirement, currently called the ''emissions limitation,'' as the ''primary emissions limitation'' and labeling the new unit-level requirement as the ''secondary emissions limitation.'' (The regulations label the designated representative-level requirement as ''compliance with the . . . assurance provisions.'')

Because the purpose of the new unit-level secondary emissions limitation is to deter conduct causing exceedances of a state's assurance level, the EPA is conditioning applicability of the new limitation on (1) the occurrence of an exceedance of the state's assurance level for the control period, and (2) the apportionment of at least some of the responsibility for the assurance level exceedance to the set of units represented by the unit's designated representative. Apportionment of responsibility for the assurance level exceedance will be carried out according to the existing assurance provision procedures and will therefore depend on the designated representative's shares of both the state's total emissions for the control period and the state's assurance level for the control period. To ensure that the secondary emissions limitation is focused on units where the need for improved incentives is greatest, and also to ensure that the limitation will not apply to units used only to meet peak electricity demand, the limitation applies only to units that are equipped with post-combustion controls (*i.e.,* SCR or SNCR) and that operated for at least ten percent of the hours in the control period in question and in at least one previous control period.

For units to which a secondary emissions limitation applies in a given control period based on the conditions just summarized, the limitation is defined by a formula in the regulations. The formula is generally designed to compute the potential amount the unit would have emitted during the control period, given its actual heat input during the control period, if the unit had achieved an average emissions rate equal to the unit's lowest average emissions rate in a previous control period plus a margin of 25 percent. To ensure that the data used to establish the unit's lowest previous average emissions rate are representative and of high quality, only past control periods where the unit participated in a CSAPR trading program for ozone season NO_X and operated in at least ten percent of the hours in the control period are considered. Further, to avoid causing units that achieve emissions rates lower than 0.08 lb/mmBtu from becoming subject to more stringent secondary emissions limitations in subsequent control periods, the secondary emissions limitation formula uses a

[341] The EPA believes that the occurrence of avoidable assurance level exceedances under the Group 2 trading program, combined with the express statutory directive that good neighbor obligations must be addressed ''within the state,'' and through ''prohibition,'' would also provide a sufficient legal basis for the Agency to promulgate the same revisions to the assurance provisions for all the other CSAPR trading programs. The EPA is not doing so at this time because the Agency has seen no reason to expect exceedances of the assurance levels under any of the other CSAPR trading programs by any of the states that will remain subject to the respective trading programs after this rulemaking, except possibly by Missouri under the CSAPR NO_X Annual Trading Program. The EPA expects that reductions in Missouri's seasonal NO_X emissions sufficient to comply with the proposed provisions of the revised Group 3 trading program, including the secondary emissions limitations, would also prevent exceedances of Missouri's currently applicable assurance level for annual NO_X emissions.

floor emissions rate of 0.10 lb/mmBtu (which is 0.08 lb/mmBtu plus the formula's 25 percent margin). In addition to making sure that performance better than 0.08 lb/mmBtu is not disincentivized, the inclusion of the floor emissions rate also ensures that no unit achieving an average emissions rate of 0.10 lb/mmBtu or less in a given control period will exceed a secondary emissions limitation in that control period. Finally, the formula includes a 50-ton threshold, which will avert violations for small performance deviations at large EGUs and also ensure that no unit emitting less than 50 tons in a given control period will exceed a secondary emissions limitation in that control period.

In summary, a secondary emissions limitation is applicable to a unit for a given control period only if the state's assurance level is exceeded, responsibility for the exceedance is apportioned at least in part to the set of units represented by the unit's designated representative, the unit is equipped with post-combustion controls, and the unit operated for at least ten percent of the hours in the control period. Where a secondary emissions limitation applies to a unit for a given control period, the amount of the limitation is computed as the sum of 50 tons plus the product of (1) the unit's heat input for the control period times (2) a NO_X emissions rate of 0.10 lb/mmBtu or, if higher, 125 percent times the lowest seasonal average NO_X emissions rate achieved by the unit in a previous control period when the unit participated in a CSAPR trading program for ozone season NO_X emissions and operated in at least ten percent of the hours in the control period.[342]

Table VI.B.8–1 shows the secondary emissions limitations that the formula would have produced and which units would have exceeded those limitations if the limitations and formula had been in effect for the Group 2 trading program in 2020 and 2021 when assurance level exceedances occurred in Missouri. Following consideration of comments, the EPA believes that in each case the formula functions in a reasonable manner, and the Missouri units identified as exceeding their respective secondary emissions limitations are sources for which an enforcement deterrent under CAA sections 113 and 304 would have been appropriate to compel better control of NO_X emissions. Table VI.B.8–1 does not show any units that would have been identified as subject to secondary emissions limitations in the case of the 2019 and 2020 assurance level exceedances in Mississippi because no units in the state meeting all conditions for applicability—including the requirement to be equipped with post-combustion controls—exceeded their respective limitations.

TABLE VI.B.8–1—ILLUSTRATIVE RESULTS OF APPLYING SECONDARY EMISSIONS LIMITATION IN PREVIOUS INSTANCES OF ASSURANCE LEVEL EXCEEDANCES

Owner/operator	Unit	125% of Lowest previously achieved NO_X emissions rate (lb/mmBtu)	Actual NO_X emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO_X emissions (tons)	Exceedance (tons)
Missouri—2020						
Assoc. Elec. Coop	New Madrid 1	0.135	0.670	961	4,524	3,563
Assoc. Elec. Coop	New Madrid 2	0.131	0.497	866	3,108	2,242
Assoc. Elec. Coop	Thomas Hill 1	0.123	0.526	374	1,384	1,010
Assoc. Elec. Coop	Thomas Hill 2	0.122	0.537	548	2,187	1,639
Assoc. Elec. Coop	Thomas Hill 3	0.104	0.195	780	1,374	594
Missouri—2021						
Assoc. Elec. Coop	New Madrid 1	0.135	0.652	353	1,466	1,113
Assoc. Elec. Coop	New Madrid 2	0.131	0.611	1,054	4,700	3,646
Assoc. Elec. Coop	Thomas Hill 1	0.123	0.146	421	440	19
Assoc. Elec. Coop	Thomas Hill 2	0.122	0.400	600	1,801	1,201

For further illustrations of the application of the secondary emissions limitation formula to other units in the states to be subject to the expanded Group 3 trading program in the control periods from 2016 through 2021, see the spreadsheet ''Illustrative Calculations Using Proposed Secondary Emissions Limitation Formula,'' available in the docket. The EPA notes that, with the exception of the units listed in Table VI.B.8–1, no unit shown in the spreadsheet as having emissions exceeding the illustrative secondary emissions limitation calculated for the unit would have violated the prohibition because no violation would occur in the absence of an exceedance of the assurance level and apportionment of responsibility for a share of the exceedance to the unit under the assurance provisions.

The secondary emissions limitation provisions are being finalized as proposed except for the addition of the condition that a unit to which the provisions apply must be equipped with post-combustion controls. The EPA's responses to comments concerning the secondary emissions limitation provisions, including the comments giving rise to the change just mentioned, are in the remainder of this section and section 5 of the *RTC* document.

Comment: Some commenters stated that the secondary emissions limitation is not necessary, or would be a disproportionate remedy, because experience shows that exceedances of the assurance level have been rare, and where exceedances of a state's assurance level have occurred, the 3-for-1 surrender ratio under the existing regulations has applied, providing a sufficient remedy.

Response: The EPA disagrees with these comments. The purpose of the assurance provisions in the CSAPR trading programs is to ensure that the emissions reductions required to address a state's obligations under the Good Neighbor Provision occur ''within the state'' as mandated by the CAA. See *North Carolina* v. *EPA,* 531 F.3d 896, 906–08 (D.C. Cir. 2008). Prior to this action, the sole consequence for an exceedance of a state's assurance level

[342] For the actual regulatory language, see 40 CFR 97.1025(c) as added by this rule.

has been a requirement to surrender two additional allowances for each ton of the exceedance. The repeated, large, foreseeable, and easily avoidable exceedances of Missouri's assurance level under the Group 2 trading program in 2020 and 2021 have made clear that a remedy based solely on additional allowance surrenders is insufficient to address this statutory requirement and that a materially stronger deterrent is needed.

Comment: Some commenters stated that the secondary emissions limitation could apply to exceedances caused by factors outside the control of the EGU operator, going beyond the EPA's intent of deterring exceedances that are foreseeable and avoidable. For example, commenters pointed out that some units that typically combust gas may sometimes be ordered to combust oil at times when supplies of gas are constrained and expressed concern that the resulting higher NO_X emissions could cause a unit to exceed its secondary emissions limitation. Another commenter stated that it is not uncommon for units' seasonal average NO_X emissions rate to vary by more than 25 percent across control periods.

Response: The EPA agrees that the secondary emissions limitation is intended to apply to units in a position to avert an exceedance of a state's assurance level. The contention that year-to-year variability of 25 percent in units' seasonal average emissions rates is common is not in itself a persuasive reason to omit the secondary emissions limitation from the final rule, because the mere existence of such variability says nothing about whether the operators of those units could reduce that variability through their operational decisions, and the commenter provided no data regarding the extent to which the historical variability was avoidable. However, the EPA agrees that a secondary emissions limitation should be designed to avoid application to a unit whose increase in emissions rate was caused by mandated combustion of a higher-NO_X fuel than the unit's normal fuel. Moreover, based on the analysis of the secondary emissions limitation formula prepared for the proposal, the EPA has reviewed the applicability of the limitation more generally and has determined that it should apply only to units with post-combustion controls, which are the units with the greatest ability to manage their emissions rates through their operating behavior. This modification will avoid application of a secondary emissions limitation in situations where a unit's increase in seasonal average NO_X emissions rate relative to past control periods is caused by factors in that control period beyond the operator's control, such as being mandated by a regulator to combust a higher proportion of oil or operating for a higher proportion of hours at load levels where the unit has a higher NO_X emissions rate for reasons other than non-operation of emissions controls.

Comment: Some commenters asserted that because it is not known if a state's assurance level has been exceeded until after the end of the control period, EGU operators would be unable to know whether the secondary emissions limitation would apply to them during the control period. Some of these commenters suggested that where a unit has been found to have contributed to an assurance level exceedance, the EPA should apply a secondary emissions limitation to the unit not in that control period but instead in the following control period.

Commenters suggested that uncertainty about whether a unit would be subject to a secondary emissions limitation could have a variety of undesirable consequences. For example, they asserted that some EGUs could become unwilling to operate when needed for reliability because they would be concerned that merely operating more than in previous control periods could cause a unit to exceed its limitation. One commenter asserted that the uncertainty would make it difficult for an owner of multiple EGUs to use allowances allocated to one EGU to meet another EGU's surrender requirements, possibly leading to operating restrictions on multiple EGUs.

Response: The EPA disagrees with these comments. While an operator cannot be certain that the secondary emissions limitation *will* apply to a particular EGU until after the end of a control period, the operator can be certain that the limitation *will not* apply to a particular EGU simply by ensuring that the unit's seasonal average NO_X emissions rate does not exceed the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest seasonal average NO_X emissions rate in a previous control period under a CSAPR trading program (excluding control periods where the unit operated for less than 10 percent of the hours). Because any operator of a unit with post-combustion controls can readily avoid being subject to the limitation, there is no need for application of the limitation to be deferred to the following control period. Deferral of the limitation's application would also have the effect of excusing a unit's first contribution to an assurance level exceedance, which the EPA views as inappropriate when that exceedance could have been avoided.

The asserted possible consequences of uncertainty about whether the limitation would apply rest on mischaracterizations of the provision. The formula for the limitation reflects the unit's actual heat input for the control period, so there is no penalty for increased operation as long as the unit's seasonal NO_X average emissions rate stays below the level just referenced. Finally, nothing about the secondary emissions limitation disincentivizes an EGU fleet owner from transferring allocated allowances among the fleet's EGUs, because apportionment of responsibility for an assurance level exceedance—one of the conditions for application of the secondary emissions limitation—is determined at the level of the group of units represented by a common designated representative (typically the set of all units operated by a particular owner) rather than the individual unit.

Comment: Some commenters stated that the EPA should revise the secondary emissions limitation formula so that where a limitation applies to a unit, the unit's previous NO_X emissions rate used in the formula would not be subject to any floor. These commenters also recommended that if the secondary emissions limitation provisions are not finalized, the EPA instead should raise the allowance surrender ratio applied to exceedances of the assurance level in this final rule.

Response: The EPA disagrees with the suggestion to remove the emissions rate floor from the secondary emissions limitation formula, which would have the effect of making the limitation more stringent for any unit that has achieved a seasonal average NO_X emissions rate lower than 0.08 lb/mmBtu in a past control period. As indicated by their label, the secondary emissions limitation provisions play a secondary role in the Group 3 trading program regulations, specifically to provide the strongest possible deterrent against conduct leading to foreseeable and avoidable exceedances of a state's assurance level. The distinguishing feature of the secondary emissions limitation provisions is therefore the remedy for an exceedance, which is potential application of the CAA's enforcement authorities. The trading program's primary role of achieving required emissions reductions in a more flexible and cost-effective manner than command-and-control regulation is played by the primary emissions limitation provisions, which are structured as allowance surrender requirements. Within this overall trading program structure, the EPA considers it sufficient for the operation of units at emissions rates lower than 0.08 lb/mmBtu to be incentivized through the allowance surrender requirements instead of being mandated through potential application of the CAA's enforcement authorities.

The recommendation to raise the allowance surrender ratio applicable to exceedances of the assurance level if the secondary emissions limitation is not finalized is moot because the secondary emissions limitation is being finalized.

9. Unit-Level Allowance Allocation and Recordation Procedures

In this rule, the EPA is establishing default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances (''Group 3 allowances'') in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. Like the allocation processes established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, the revised allocation process finalized in this rule is designed to provide default allowance allocations to all units that are subject to allowance holding requirements. The EPA's allocations and allocation procedures apply for the 2023 control period [343] and, by default, for subsequent control periods unless and until a state or tribe provides state-determined or tribe-determined allowance allocations under an approved SIP revision or tribal implementation plan.[344]

The default allocation process for the Group 3 trading program as updated in this rule involves three main steps. First, portions of each state emissions budget for each control period are reserved for potential allocation to units that are subject to allowance holding requirements and that might not otherwise receive allowance allocations in the overall allocation process, including both ''existing'' units in any areas of Indian country not subject to a state's CAA implementation planning authority as well as ''new'' units anywhere within a state's borders.[345] Second, in advance of each control period, the unreserved portion of the state budget is allocated among the state's eligible existing units, any portion of the state budget reserved for existing units in Indian country not subject to the state's CAA implementation planning authority is allocated among those units, and the allocations are recorded in the respective sources' compliance accounts. Finally, after the control period but before the compliance deadline by which sources must hold allowances to cover their emissions for the control period, allowances from the portion of the budget reserved for new units are allocated to qualifying units, any remaining reserved allowances not allocated to qualifying units are allocated among the state's existing units, and the allocations are recorded in the respective sources' compliance accounts.

While the overall three-step allocation process summarized in this section was also followed in CSAPR, the CSAPR Update, and the Revised CSAPR Update, in this rule the EPA is making revisions to each step to better address units in Indian country and to better coordinate the unit-level allocation process with the dynamic budget-setting process discussed in section VI.B.4 of this document. The revisions to the three steps are discussed in sections VI.B.9.a, VI.B.9.b, and VI.B.9.c, respectively.

a. Set-Asides of Portions of State Emissions Budgets

The first step of the overall unit-level allocation process for a given control period involves reserving portions of each state's budget for the control period in ''set-asides.'' In this rule, the EPA is making several revisions affecting the establishment of set-asides. The first revision, which is largely unrelated to the other aspects of this rulemaking, will update the regulations for the Group 3 trading program [346] to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that the relevant states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area.[347] Consistent with this holding, the EPA is revising language in the Group 3 trading program regulations that prior to this rule, for purposes of allocating allowances from a given state's emissions budget, distinguished between (1) the set of units within the state's borders that are not in Indian country and (2) the set of units within the state's borders that are in Indian country. As revised, the provisions now distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. The revised language more accurately distinguishes which units are, or are not, covered by a state's CAA implementation planning authority, which is the underlying purpose for which the term ''Indian country'' is currently used in the allowance allocation provisions. The effect of the revision is that any units located in areas of ''Indian country'' as defined in 18 U.S.C. 1151 that are covered by a state's CAA implementation planning authority will be treated for allowance allocation purposes in the same manner as units in areas of the state that are not Indian country, consistent with the *ODEQ* holding.[348]

The remaining revisions, which are interrelated, concern the types of set-asides that in the context of this rule will best accomplish the goal of ensuring the availability of allocations to units that are subject to allowance holding requirements and that would

343 The rule does not include an option for states to replace the EPA's unit-level allocations for the 2023 control period because the Agency believes a process for obtaining appropriately authorized allowance allocations determined by a state or tribe could not be completed in time for those allocations to be recorded before the end of the 2023 control period.

344 The options for states to submit SIP revisions that would replace the EPA's default allowance allocations are discussed in sections VI.D.1, VI.D.2, and VI.D.3 of this document. Similarly, for a covered area of Indian country not subject to a state's CAA implementation planning authority, a tribe could elect to work with the EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations that would replace the EPA's default allocations for subsequent control periods.

345 Under this rule, the unit-level allocations to ''existing'' units are generally computed in the year before the year of each control period, and the determination of whether to treat a particular unit as existing for purposes of that control period's allocations is made as part of the allocation process, generally based on whether the Agency has the data needed to compute an allocation for the unit as an existing unit. A unit that is subject to allowance holding requirements for a given control period and that did not receive an allocation for that control period as an existing unit is generally eligible to receive an allocation from the portion of the budget reserved for ''new'' units. For further discussion of which units are considered eligible for allocations as existing units or new units in particular control periods, see sections VI.B.9.b and VI.B.9.c.

346 As discussed in section VI.B.13, the EPA is also making this revision to the regulations for the other CSAPR trading programs in addition to the Group 3 trading program.

347 For additional discussion of the *ODEQ* v. *EPA* decision and other issues related to the CAA implementation planning authority of states, tribes, and the EPA in various areas of Indian country, *see* section III.C.2.

348 The EPA notes that the units that will be treated for allocation purposes in the same manner as units not in Indian country will include units in any areas of Indian country subject to a state's CAA implementation planning authority, whether those are non-reservation areas (consistent with *ODEQ*) or reservation areas (such as areas of Indian country within Oklahoma's borders covered by the EPA's October 1, 2020 approval of Oklahoma's request under SAFETEA, as discussed in section III.C.2).

not otherwise receive allowance allocations. One revision to the types of set-asides addresses allocations to existing units in Indian country. The revised geographic scope of the Group 3 trading program under this rule will for the first time include an existing EGU in Indian country not covered by a state's CAA implementation planning authority—the Bonanza coal-fired unit in the Uintah and Ouray Reservation within Utah's borders. To provide an option for Utah (or a similarly situated state in the future) to replace the Agency's default allowance allocations to most existing units with state-determined allocations through a SIP revision while continuing to ensure the availability of a default allocation to the Bonanza unit, which is not subject to the state's jurisdiction or control (or similarly situated units in the future), the EPA is revising the Group 3 trading program regulations to provide for ''Indian country existing unit set-asides.'' Specifically, for each state and for each control period where the set of units within a state's borders eligible to receive allocations as existing units includes one or more units [349] in an area of Indian country not covered by the state's CAA implementation planning authority, the EPA will reserve a portion of the state's emissions budget in an Indian country existing unit set-aside for the unit or units. The amount of each Indian country existing unit set-aside will equal the sum of the default allocations that the units covered by the set-aside would receive if the allocations to all existing units within the state's borders were computed according to EPA's default allocation procedure (which is discussed in section VI.B.9.b of this document). Immediately after determining the amount of a state's emissions budget for a control period (and after reserving a portion for potential allocation to new units, as discussed later in this section), the EPA will first determine the default allocations for all existing units within the state's borders, then allocate the appropriate quantity of allowances to the Indian country existing unit set-aside, then allocate the allowances from the set-aside to the covered units in Indian country, and finally record the allocations in the sources' compliance accounts at the same time as the allocations to other sources not in Indian country. The existence of the Indian country existing unit set-aside thus will have no substantive effect unless and until the relevant state chooses to replace the EPA's default allowance allocations through a SIP revision, in which case the state would have the ability to establish state-determined allocations for the units subject to the state's CAA implementation planning authority while the EPA would continue to administer the Indian country existing unit set-aside for the units in Indian country not covered by the state's CAA implementation planning authority.[350] The EPA believes the establishment of Indian country existing unit set-asides accomplishes the objective of allowing states to control allowance allocations to units covered by their CAA implementation planning authority while ensuring that the allocations to units in Indian country not covered by such authority remain under Federal authority (unless replaced by a tribal implementation plan).

The remaining revisions to the types of set-asides address the set-asides used to ensure availability of allowance allocations to *new* units in light of the division of the budget for *existing* units into a reserved portion for existing units in Indian country and an unreserved portion for other existing units. Under the Group 3 trading program regulations as in effect before this rule, allowances for new units have been provided from separate new unit set-asides and Indian country new unit set-asides. Under this rule, the EPA is combining these two types of set-asides starting with the 2023 control period by eliminating the Indian country new unit set-asides and expanding eligibility for allocations from the new unit set-asides to include units anywhere within the relevant states' borders. However, as with the Indian country new unit set-asides under the current regulations, the EPA will continue to administer the new unit set-asides in the event a state chooses to replace the EPA's default allocations to existing units with state-determined allocations, thereby ensuring the availability of allocations to any new units not covered by a state's CAA implementation planning authority.

The reason for the revisions to the new unit set-asides and Indian country new unit set-asides is to avoid unnecessary and potentially inequitable changes to the degree to which individual existing units contribute to, or benefit from, the new unit set-asides. The allowances used to establish these set-asides are reserved from each state emissions budget before determination of the allocations from the unreserved portion of the budget to existing units, so that certain existing units—generally those receiving the largest allocations—contribute to creation of the set-asides through roughly proportional reductions in their allocations. Later, if any allowances in a set-aside are not allocated to qualifying new units, the remaining allowances are reallocated to the existing units in proportion to their initial allocations from the unreserved portion of the budget, so that certain existing units—again, generally those receiving the largest allocations—benefit from the reallocations in rough proportion to their previous contributions.[351] The EPA believes maintaining this symmetry, where the same existing units—whether in Indian country or not—both contribute to and potentially benefit from the set-asides, is a reasonable policy objective, and doing so requires that the EPA continue to administer the new unit set-asides in the event a state chooses to replace the EPA's default allocations to existing units with state-determined allocations, because otherwise the EPA would be unable to maintain Federal implementation authority and ensure that the units in Indian country would receive an appropriate share of any reallocated allowances.[352] The principal difference between the new unit set-asides and the Indian country new unit set-asides under the regulations in effect before this rule was that, if a state chose to replace the EPA's default allocations with state-determined allocations, the state would take over administration of the new unit set-aside, but not any Indian country new unit set-aside.

[349] In coordination with the dynamic budgeting process discussed in section VI.B.4, each unit included in the unit inventory used to determine a state's dynamic emissions budget for a given control period in 2026 or a later year will be considered an ''existing'' unit for that control period for purposes of the determination of unit-level allowance allocations. In other words, there will no longer be a single fixed date that divides ''existing'' from ''new'' units.

[350] As noted in section VI.D, a tribe could elect to work with EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations for units in the relevant area of Indian country that would replace EPA's default allocations for subsequent control periods.

[351] Under the regulations in effect before this final rule, allowances from an Indian country new unit set-aside that are not allocated to qualifying new units in Indian country are first transferred to the state's new unit set-aside, and if the allowances are not allocated to qualifying new units elsewhere within the state's borders, the allowances are then reallocated to the state's existing units.

[352] If units in Indian country were unable to share in the benefits of reallocation of allowances from the new unit set-asides, it would be possible to achieve a different form of symmetry by simultaneously exempting the units in Indian country from the obligation to share in the contribution of allowances to the new unit set-asides. However, some stakeholders might view this alternative as potentially inequitable because existing units in Indian country would then make no contributions toward the new unit set-aside while other existing units would still be required to do so.

Under the revised regulations finalized in this rule, states will not be able to take over administration of the new unit set-asides in this situation. Therefore, there is no longer any reason to establish separate Indian country new unit set-asides in order to preserve Federal (and potentially tribal) authority to implement the rule in areas of Indian country subject to tribal jurisdiction.

With respect to the total amounts of allowances that will be set aside for potential allocation to new units from the emissions budgets for each state, for the control periods in 2023 through 2025 (but not for subsequent control periods, as discussed later in this section), the EPA is establishing total set-aside amounts equal to the projected amounts of emissions from any planned units in the state for the control period, plus an additional base 2 percent of the state emissions budget to address any unknown new units, with a minimum total amount of 5 percent. For example, if planned units in a state are projected to emit 4 percent of the state's NO_X ozone season emissions budget, then the new unit set-aside for the state would be set at 6 percent, which is the sum of the 4 percent for planned units plus the base 2 percent for unknown new units. Alternatively, if planned new units are projected to emit only 1 percent of the state's budget, the new unit set-aside would be set at the minimum 5 percent amount. Except for the addition of the 5 percent minimum, which is a change being made in response to comments, the approach to setting the new unit set-aside amounts is generally the same approach previously used to establish the amounts of new unit set-asides in CSAPR, the CSAPR Update, and the Revised CSAPR Update for all the CSAPR trading programs. *See, e.g.,* 76 FR 48292 (August 8, 2011).

As under the Revised CSAPR Update, the EPA is making an exception for New York for the 2023 through 2025 control periods, establishing a total new unit set-aside amount for each control period of 5 percent of the state's emissions budget, with no additional consideration for planned units, because this approach is consistent with New York's preferences as reflected in an approved SIP addressing allowance allocations for the Group 2 trading program.

The final regulations issued under this rule specify the new unit set-aside amounts in terms of the percentages of the state emissions budgets. The amounts are shown in Tables VI.B.9.a–1, VI.B.9.a–2, and VI.B.9.a–3 of this document show the tonnage amounts of the new unit set-asides for the control periods in 2023 through 2025 that are computed by multiplying the new unit set-aside percentages by the preset budgets finalized in this rule for those control periods. The amounts of the 2023 new unit set-asides are illustrative because they do not reflect the impact of transitional adjustments included in the rule that that are likely to affect the 2023 budgets as implemented.[353] The amounts of the 2024 and 2025 new unit set-asides are the actual amounts, because the 2024 and 2025 budgets computed in this rule are the budgets that will be implemented, without any need for transitional adjustments.

TABLE VI.B.9.a–1—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2023 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,379	5	319
Arkansas	8,927	5	446
Illinois	7,474	5	374
Indiana	12,440	5	622
Kentucky	13,601	5	680
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,727	5	536
Minnesota	5,504	5	275
Mississippi	6,210	5	311
Missouri	12,598	5	630
Nevada	2,368	9	213
New Jersey	773	5	39
New York	3,912	5	196
Ohio	9,110	6	547
Oklahoma	10,271	5	514
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,755	5	788
Virginia	3,143	5	157
West Virginia	13,791	5	690
Wisconsin	6,295	5	315

[353] As discussed in section VI.B.12, the EPA expects that this final rule will become effective after May 1, 2023, causing the emissions budgets for the 2023 control period to be adjusted under the rule's transitional provisions so as to ensure that the new budgets will apply only after the rule's effective date. The actual new unit set-asides for the 2023 control period will be computed using the adjusted budgets, but the 2023 budget amounts shown in Table VI.B.9.a–1 do not reflect these adjustments.

TABLE VI.B.9.a–2—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2024 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,999	5	650
Louisiana	9,363	5	468
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,058	5	253
Missouri	11,116	5	556
Nevada	2,589	9	233
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,384	5	469
Pennsylvania	8,138	5	407
Texas	40,134	5	2,007
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	6,295	5	315

TABLE VI.B.9.a–3—CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2025 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,489	5	324
Arkansas	8,927	5	446
Illinois	7,325	5	366
Indiana	11,413	5	571
Kentucky	12,472	5	624
Louisiana	9,107	5	455
Maryland	1,206	5	60
Michigan	10,275	5	514
Minnesota	4,058	5	203
Mississippi	5,037	5	252
Missouri	11,116	5	556
Nevada	2,545	9	229
New Jersey	773	5	39
New York	3,912	5	196
Ohio	7,929	6	476
Oklahoma	9,376	5	469
Pennsylvania	8,138	5	407
Texas	38,542	5	1,927
Utah	15,917	5	796
Virginia	2,756	5	138
West Virginia	11,958	5	598
Wisconsin	5,988	5	299

For control periods in 2026 and later years, the EPA will allocate a total of 5 percent of each state emissions budget to a new unit set-aside, with no additional amount for planned new units. The amounts of the set-asides for each state and control period will be computed when the emissions budgets for the control period are established, by May 1 of the year before the year of the control period. The procedure for determining the amounts of the set-asides based on the amounts of the state emissions budgets is being codified in the Group 3 trading program regulations and will reflect the same percentage of the emissions budget for all states.

The purpose of the change to the procedure for establishing the amounts of the set-asides is to coordinate with the dynamic budget-setting process that may be used to determine budgets beginning with the 2026 control period. As discussed in section VI.B.4 of this document, under the dynamic budget-setting process, each state's budget for each control period will be computed using fleet composition information and the total ozone season heat input reported by all affected units in the state for the most recent control periods before the budget-setting computations. (For example, 2026 emissions budgets would be based on 2022–2024 state-level heat input data.) Moreover, as discussed in section VI.B.9.b of this document, the set of units eligible to receive allocations as ''existing'' units in a given control period will generally be the set of units that operated in the control period two years earlier (with the exception of any units whose monitor certification deadlines fell after the start of that earlier control period). Consequently, by the 2025 control period, all or almost all units that commenced commercial operation before issuance of this rule will be considered ''existing'' units for purposes of budget-setting and allocations, and units commencing commercial operation after issuance of this rule generally will be considered ''existing'' units for all but their first two full control periods of operation (and possibly a preceding partial control period). Given that new units will not be relying on the new unit set-asides as a permanent source of allowances, as is the case for ''new'' units under the other CSAPR trading programs, the EPA believes it is unnecessary to establish set-aside percentages for some states that are permanently larger than 5 percent based solely on the fact that projected emissions from planned new units happen to be a somewhat larger proportion of those states' overall budgets at the time of this rule's issuance.

The changes to the structure and amounts of set-asides in this rule largely follow the proposal. The EPA received few comments on these topics. As noted previously, one commenter expressed the view that if the amounts of the new unit set-asides were based on 2 percent of the respective states' budgets, the set-asides would be too small in certain circumstances, and in response the final rule bases the amounts of the set-asides on a floor percentage of 5 percent instead of 2 percent. The remaining commenters expressed a concern that the final rule's provisions regarding set-asides should ensure that any tribal decisions relating to allowance allocations would not be constrained by state decisions. The EPA had this same concern in mind when designing the rule and believes that the final set-aside structure—encompassing Indian country existing unit set-asides as well as EPA-administered new unit set-asides for sources in all areas within each state's borders—fully addresses the concern, is equitable, and preserves Federal and tribal authority under this rule for areas of Indian country subject to tribal jurisdiction. The comments and the EPA's responses are discussed in greater detail in section 1 of the *RTC* document.

b. Allocations to Existing Units, Including Units That Cease Operation

In conjunction with the new and revised state emissions budget-setting methodology for the Group 3 trading program finalized in this rulemaking, the EPA is necessarily establishing a revised procedure for making unit-level allocations of Group 3 allowances to existing units.[354] The procedure that the EPA is employing to compute the unit-level allocations is very similar but not identical to the procedure used to compute unit-level allocations for units subject to the Group 3 trading program in the Revised CSAPR Update. The steps of the procedure for determining allocations from each state emissions budget for each control period are described in detail in the Unit-Level Allowance Allocations Final Rule TSD. The steps are summarized in the following paragraphs, with changes from the procedure followed in the Revised CSAPR Update noted.

In the first step, the EPA identifies the list of units eligible to receive allocations for the control period. The unit inventories used to compute unit-level allocations for the control periods in 2023 through 2025 are the same inventories that have been used to determine the preset emissions budget for these control periods. These inventories have been determined in this rulemaking in essentially the same manner as in the Revised CSAPR Update. The procedures for updating the unit inventories for these control periods are discussed in section VI.B.4 of this document, and the criteria that the EPA has applied to determine whether a unit's scheduled retirement is sufficiently certain to serve as a basis for adjusting emissions budgets and unit-level allocations, are discussed in section V.B of this document and in the Ozone Transport Policy Analysis Final Rule TSD.

The unit inventories used to compute unit-level allocations for control periods in 2026 and later years will be determined in the year before the control period in question based on the latest reported emissions and operational data, which is an extension of the methodology used in the Revised CSAPR Update to reflect more recent data (for example, the unit inventories used to compute 2026 budgets and allocations will reflect reported data up through the 2024 control period). These inventories, which are generally the same as the inventories used to compute dynamic budgets for each control period, include any unit whose monitor certification deadline was no later than the start of the relevant historical control period and that reported emissions data during the relevant historical control period. The EPA notes that basing the list of eligible units on the list of units that reported heat input in the control period two years earlier than the control period for which allocations are being determined represents a revision to the Group 3 trading program regulations as in effect before this rule concerning the treatment of allocations to retired units. Under the prior regulations, units that cease operations for two consecutive control periods would continue to receive allocations as existing units for three additional years (that is, a total of five years) before the allowances they would otherwise have received are reallocated to the new unit set-aside for the state. Under the regulations as revised in this rule, units that cease operation will receive allocations for only two full control periods of non-operation. While the EPA has in prior transport rulemakings noted a qualitative concern that ceasing allowance allocations prematurely could distort the economic incentives of EGUs to continue operating when retirement is more economical, the EPA believes that anticipated market conditions (in particular, the incentives toward power sector transition to cleaner generating sources), particularly in the later 2020s, are such that a continuation of allowance allocations to retiring units likely has no more than a de minimis effect on the consideration of an EGU whether to retire or not.

In the second step of the procedure for determining allocations to existing units, the EPA will compile a database containing for each eligible unit the unit's historical heat input and total NO_X emissions data for the five most recent ozone seasons. For each unit, the EPA will compute an average heat input value based on the three highest non-zero heat input values over the 5-year period, or as the average of all the non-zero values in the period if there are fewer than three non-zero values. For each unit, the EPA will also determine the maximum total NO_X emissions value over the 5-year period. For coal-

[354] The revisions to the procedures for computing unit-level allowance allocations in this rulemaking apply only to the Group 3 trading program. In this rulemaking, the EPA is not reopening the methodology for computing the amounts of allowances allocated to any unit under any other CSAPR trading program.

fired units of 100 MW or larger, the EPA will further determine a ''maximum controlled baseline'' NO_X emissions value, computed as the unit's maximum heat input over the 5-year period times a NO_X emissions rate of 0.08 lb/mmBtu. The maximum controlled baseline will serve as an additional cap on unit-level allocations for all such coal-fired units starting with the control periods in which the assumed use of SCR controls at the units is reflected in the state emissions budgets. Thus, the maximum controlled baseline will apply for purposes of allocations to units with existing SCR controls for all control periods starting with the 2024 control period and for all other coal-fired units of 100 MW or more (except circulating fluidized bed units) starting with the 2027 control period. These procedures are nearly identical to the procedures used in the Revised CSAPR Update, with three exceptions. First, instead of using only the data available at the time of the rulemaking, for each control period the EPA will use data from the most recent five control periods for which data had been reported. (For example, for the 2026 control period, the EPA will use data for the 2020–2024 control periods.) Second, to simplify the data compilation process, the EPA will use only a five-year period for NO_X mass emissions, in contrast to the 8-year period used in the Revised CSAPR Update for NO_X mass emissions. Third, the use of the maximum controlled baseline as an additional cap on emissions is a change adopted in this rule in response to comments received on the proposal. Specifically, commenters observed that if a state's emissions budget is decreased to reflect an assumption that a particular unit in the state is capable of reducing its emissions through the installation of new SCR controls, but the historical emissions cap applied to that unit in the unit-level allocation methodology does not reflect use of the new controls, then the allocation methodology could have the effect of reducing unit-level allocations to the other units in the state whose historical emissions already reflect use of existing controls rather than the unit assumed to install new controls. The EPA agrees with the comment and in this rule has added the maximum controlled baseline provision to the allocation methodology to mitigate the potential effect identified by the commenters.

In the third step of the procedure for determining allocations to existing units in each state, the EPA will allocate the available allowances for that state among the state's eligible units in proportion to the share each unit's average heat input value represents of the total of the average heat input values for all the state's eligible units, but not more than the unit's maximum total NO_X value or, if applicable, the unit's maximum controlled baseline. If the allocations to one or more units are curtailed because of the units' applicable caps, the EPA will iterate the calculation procedure as needed to allocate the remaining allowances, excluding from each successive iteration any units whose allocations have already reached their caps. (If all units in a state reach their caps, any remaining allowances are allocated in proportion to the units' average heat input values, notwithstanding the caps.) This calculation procedure is identical to the calculation procedure used in the Revised CSAPR Update (as well as the CSAPR Update and CSAPR), but using caps that reflect both the units' maximum historical NO_X values and also, where applicable, the maximum controlled baseline values.

Illustrative unit-level allocations for the 2023 control period and final unit-level allocations for the 2024 and 2025 control periods are being determined in this rulemaking based on the emissions budgets for those control periods also determined in the rulemaking and are included in the docket. The 2023 allocations are only illustrative because, as discussed in section VI.B.12.a, the EPA expects the effective date of the rule to occur after the start of the 2023 control period and consequently expects the 2023 control period to be a transitional period in which the emissions budgets determined in this rulemaking apply only for the portion of the control period occurring on and after the rule's effective date, while any previously determined emissions budgets apply for the portion of the control period before the rule's effective date. The rule's effective date will become known when the rule is published in the **Federal Register**. As soon as practicable thereafter, the EPA will calculate the final prorated or blended 2023 state emissions budgets and 2023 unit-level allocations based on the transitional formulas finalized in this action (see section VI.B.12.a of this document) and will communicate the information to the public through a notice of data availability. The 2023 and 2024 allocations will then be recorded 30 days after the effective date of the final rule (to provide an interval in which to execute the recall of 2023 and 2024 Group 2 allowances, as discussed in section VI.B.12.c of this document), while the 2025 allocations will be recorded by July 1, 2024.[355]

The default unit-level allocations for each control period in 2026 or a later year will be computed immediately following the determination of the state emissions budgets for the control period. The EPA will perform the computations and issue a notice of data availability concerning the preliminary unit-level allocations for each control period by March 1 of the year before the control period. There will be a 30-day period in which objections to the data and preliminary computations may be submitted, and the EPA will then make any appropriate revisions and issue another notice of data availability by May 1 of the year before the control period. The EPA will then record the allocations by July 1 of the year before the control period.[356]

All covered states also have options to establish state-determined allowance allocations for control periods in 2024 and later years. As discussed in section VI.D.1 of this rule, a state choosing to establish state-determined allocations for the 2024 control period would need to submit a letter of intent to the EPA by August 4, 2023, and would need to submit the SIP revision with the allocations by September 1, 2023. The EPA would defer recordation of the 2024 allocations for the state's sources until March 1, 2024, to provide time for this process to be completed. As discussed in sections VI.D.2 and VI.D.3 of this rule, a state choosing to establish state-determined allocations for control periods in 2025 and later years would need to submit a SIP revision by December 1 of the year two years before the first year for which state-determined allocations are being established—*e.g.,* by December 1, 2023, for allocations for the 2025 control period—and would need to submit the allocations for each control period by June 1 of the year before the control period—*e.g.,* by June 1, 2024, for allocations for the 2025

[355] The recordation schedule for the 2023 and 2024 allocations represents an expected acceleration of the recordation schedule in effect immediately before this final rule, which called for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded by September 1, 2023. *See* Deadlines for Submission and Recordation of Allowance Allocations Under the Cross-State Air Pollution Rule (CSAPR) Trading Programs and the Texas SO_2 Trading Program (the ''Recordation Rule''), 87 FR 52473 (August 26, 2022).

[356] The current recordation schedule, which provides for almost all allowance allocations to existing units for a given control period under all the CSAPR trading programs to be recorded by July 1 of the year before the year of that control period, was adopted in the Recordation Rule.

control period.[357] The EPA would record any state-determined allocations for control periods in 2025 and later years by July 1 of the year before the control period, simultaneously with the recordation of allocations to units in states where the EPA determines the unit-level allocations.

The EPA notes that for the three states with approved SIP revisions establishing their own methodologies for allocating Group 2 allowances—Alabama, Indiana, and New York—the EPA will follow the states' methodologies to the extent possible in developing the EPA's allocations of Group 3 allowances to the units in those states for the control periods in 2023 through 2025.[358] The EPA will not follow any state-specific methodologies as part of the procedures for determining default unit-level allocations of Group 3 allowances for control periods in 2026 or later years. However, like other states, these three states have options to replace the EPA's default allocations with state-determined allocations through SIP revisions starting with the 2024 control period.

As an exception to all of the recordation deadlines that would otherwise apply, the EPA will not record any allocations of Group 3 allowances in a source's compliance account unless that source has complied with the requirements to surrender previously allocated 2023–2024 Group 2 allowances. The surrender requirements are necessary to maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this final rule. The EPA finds that it is reasonable to condition the recordation of Group 3 allowances on compliance with the surrender requirements because the condition will spur compliance and will not impose an inappropriate burden on sources. The EPA considers establishment of this condition, which will facilitate the continued functioning of the Group 2 trading program, to be an appropriate exercise of the Agency's authority under CAA section 301 (42 U.S.C. 7601) to prescribe such regulations as are necessary to carry out its functions under the Act.

The provisions governing allocations to existing units are being finalized substantially as proposed, except for the addition of an additional cap on unit-level allocations in response to comments. The EPA's responses to comments on the unit-level allocation provisions for existing units are in section 5 of the *RTC* document.

c. Allocations From Portions of State Emissions Budgets Set Aside for New Units

The Group 3 trading program regulations provide for the EPA to allocate allowances from each new unit set-aside after the end of the control period at issue. An eligible new unit for purposes of allocations from a set-aside for a given control period is generally any unit in the relevant area that reported emissions subject to allowance surrender requirements during the control period and that was not eligible to receive an allowance allocation as an ''existing'' unit for the control period. Thus, in addition to units that have not yet completed two full control periods of operation since their monitor certification deadlines, units eligible for allocations from the new unit set-asides may also include existing coal-fired units that first lose their eligibility for allocations from the unreserved portion of the applicable state budget by ceasing operation, and then resume operation in a later control period. The regulations call for the EPA to allocate allowances to any eligible ''new'' units in the state generally in proportion to their respective emissions during the control period, up to the amounts of those emissions if the relevant set-aside contains sufficient allowances, and not exceeding those emissions. However, in the case of a unit whose allocation for the control period would have been subject to a maximum controlled baseline if the unit was eligible to receive allocations as an existing unit, the unit's allocation from the new unit set-aside will not exceed a cap equal to the unit's reported heat input for the control period times an emissions rate of 0.08 lb/mmBtu.

Any allowances remaining in a new unit set-aside after the allocations to new units are reallocated to the existing units in the state in proportion to those units' previous allocations for the control period as existing units. The EPA issues a notice of data availability concerning the proposed allocations by March 1 following the control period, provides an opportunity for submission of objections, and issues a final notice of data availability and record the allocations by May 1 following the control period, one month before the June 1 compliance deadline.

This EPA notes that the revisions to other provisions of the Group 3 trading program regulations discussed elsewhere in this document will reduce the portions of the state emissions budgets that are allocated through the new unit set-asides. Specifically, because the new unit set-asides will no longer receive any additional allowances when units retire, for control periods in 2025 and later years the amounts of allowances in the new unit set-asides will always be 5 percent of the respective state emissions budgets for the respective control periods. This limit on growth of the new unit set-asides is appropriate given that the number of consecutive control periods for which any particular unit is likely to receive allocations from a state's new unit set-aside will be reduced to two full control periods (and possibly a partial control period before those two control periods) before the unit becomes eligible to receive allocations as an ''existing'' unit from the unreserved portion of the state's emissions budget. This approach contrasts with the approach under the other CSAPR trading programs where a new unit never becomes eligible to receive allocations from the unreserved portion of the emissions budget and where the new unit set-aside therefore needs to grow to accommodate an ever-increasing share of the state's total emissions.

The EPA also notes that, as discussed in sections VI.D.2 and VI.D.3 of this document, in the event that a state chooses to replace EPA's default allowance allocations under the Group 3 trading program with state-determined allocations through a SIP revision, the EPA will continue to administer the portion of each state emissions budget reserved in a new unit set-aside to ensure the availability of allowance allocations to new units in any areas of Indian country within the state not covered by the state's CAA implementation planning authority.

The final rule's provisions concerning unit-level allocations from the new unit set-asides are unchanged from the proposal except for the addition of the allocation cap in a given control period for any unit that would have been subject to a maximum controlled baseline if the unit was eligible to receive an allocation as an existing unit

[357] The current deadlines for states to submit state-determined allowance allocations to the EPA were adopted in the Recordation Rule and are coordinated with the schedule for computation of state emissions budgets for control periods in 2026 and later years. For example, for the 2026 control period, by May 1, 2025, the EPA will publish the final state emissions budgets and the EPA's default unit-level allocations; by June 1, 2025, states will submit any state-determined unit-level allocations that would replace the default allocations; and by July 1, 2025, the EPA will record the default unit-level allocations or the state-determined unit-level allocations, as applicable, in sources' compliance accounts.

[358] For discussion of how the EPA is using the previously approved allocation methodologies for Alabama, Indiana, and New York to determine allocations to units in these states for the 2023–2025 control periods, see the Allowance Allocation Final Rule TSD.

for that control period.[359] This change was made to address the same comments discussed in section VI.B.9.b of this document that caused the Agency to add the maximum controlled baseline provision to the procedure for allocating allowances to existing units. The Agency did not receive any other comments on the proposed provisions concerning unit-level allocations of allowances from the new unit set-asides.

d. Incorrectly Allocated Allowances

The Group 3 trading program regulations as promulgated in the Revised CSAPR Update include provisions addressing incorrectly allocated allowances. With regard to any allowances that were incorrectly allocated and are subsequently recovered, the provisions as in effect prior to this rule have generally called for the recovered allowances to be reallocated to other units in the relevant state (or Indian country within the borders of the state) through the process for allocating allowances from the new unit set-aside (or Indian country new unit set-aside) for the state. If the procedures for allocating allowances from the set-asides have already been carried out for the control period for which the recovered allowances were issued, the allowances would be allocated through the set-asides for subsequent control periods.

The EPA continues to view the current provisions for disposition of recovered allowances as reasonable in the case of any allowances that are recovered before the deadline for recording allocations of allowances from the new unit set-aside for the control period for which the recovered allowances were issued. However, in the case of any allowances that are recovered after that deadline, adding the recovered allowances to the new unit set-aside for a subsequent control period, as provided in the current regulations, would be inconsistent with the trading program enhancements discussed elsewhere in this document, where the amounts of allowances provided in the state emissions budgets for each control period are designed to reflect the most current available information on fleet composition and utilization and where the quantities of banked allowances available for use in each control period are recalibrated for consistency with the state emissions budgets. The EPA is therefore finalizing revisions to provide that, starting with allowances allocated for the 2024 control period, any incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-aside for that control period (*i.e.,* May 1 of the year following the control period) will be transferred to a surrender account instead of being reallocated to other units in the state. The EPA received no comments on this proposed revision, which is being finalized as proposed.

10. Monitoring and Reporting Requirements

The Group 3 trading program requires monitoring and reporting of emissions and heat input data in accordance with the provisions of 40 CFR part 75. Under 40 CFR part 75, a given unit may have several options for monitoring and reporting. Any unit can use CEMS. Qualifying gas- or oil-fired units can use certain excepted monitoring methodologies that rely in part on fuel-flow metering in combination with CEMS-based or testing-based NO_X emissions rate data. Certain non-coal-fired, low-emitting units can use a low mass emissions (LME) methodology, and sources can seek approval of alternative monitoring systems approved by the Administrator through a petition process. Each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied to produce a conservative estimate of emissions for the period involved. Further, 40 CFR part 75 requires electronic submission of quarterly emissions reports to the Administrator, in a format prescribed by the Administrator. The quarterly reports will contain all the data required concerning ozone season NO_X emissions under the Group 3 trading program.

In this rulemaking, as proposed, the EPA is making two changes to the Group 3 trading program's previous requirements related to monitoring, recordkeeping, and reporting. First, the EPA is revising the monitor certification deadline in the Group 3 trading program regulations applicable to certain units that have not already certified monitoring systems for use under 40 CFR part 75. This revision is expected to provide approximately 15 EGUs in Nevada and Utah with 180 days following the rule's effective date to certify monitoring systems, with the consequence that the units are expected to become subject to allowance holding requirements under the Group 3 trading program starting with the 2024 control period. Second, to implement the trading program enhancements, the EPA is adding certain new recordkeeping and reporting requirements, which will be implemented through amendments to the regulations in 40 CFR part 75 and will apply starting January 1, 2024. Sources generally will be able to meet the additional recordkeeping and reporting requirements using the data that are already collected by their current monitoring systems, and the EPA is not requiring the installation of additional monitoring systems at any source. However, a small number of sources with common stacks could find it advantageous to upgrade their monitoring systems so as to monitor at the individual units instead of monitoring at the common stack. The Group 3 trading program monitor certification deadline revisions and the additional recordkeeping and reporting requirements are discussed in sections VI.B.10.a and VI.B.10.b, respectively.[360]

a. Monitor Certification Deadlines

In general, a unit subject to the Group 3 trading program must monitor and report emissions data using certified monitoring systems starting as of the date the unit enters the trading program or, if later, 180 days after the unit commences commercial operation. Where an EGU has already certified and maintained monitoring systems in accordance with 40 CFR part 75 for purposes of another trading program, no recertification solely for purposes of entering the Group 3 trading program is required. Under these pre-existing provisions of the Group 3 trading program regulations, nearly all currently operating EGUs transitioning to the trading program under this rule are positioned to begin monitoring and reporting under the trading program as of their dates of entry (or if later, 180 days after they commence commercial operation) because of the units' previous requirements to monitor and report emissions under other programs including the CSAPR NO_X Ozone Season Group 2 Trading Program (for

[359] As discussed in section IX.B of this rule, the EPA is relocating some of the regulatory provisions relating to administration of the new unit set-asides and is also removing certain provisions that are made obsolete by revisions to other provisions of the Group 3 trading program regulations.

[360] The EPA is not amending the existing provisions of the Group 3 trading program regulations that govern whether units covered by the program must record and report required data on a year-round basis or may elect to record and report required data on an ozone season-only basis. *See* 40 CFR 97.1034(d)(1); *see also* 40 CFR 75.74(a)-(b). Thus, for units that are required or elect to report other data on a year-round basis, the additional recordkeeping and reporting requirements will also apply year-round, while for units that are allowed and elect to report other data on an ozone season-only basis, the additional requirements will also apply for the ozone season only.

units in Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin), the CSAPR NO_X Annual Trading Program (for units in Minnesota), and the Acid Rain Program (for most units in Nevada and Utah).

As discussed in section VI.B.3 of this document, the EPA has identified 15 potentially affected units in Nevada and Utah that commenced commercial operation more than 180 days before the effective date of this rule and that do not currently report emissions data to the Agency under 40 CFR part 75.[361] To ensure that units in this situation have sufficient time to certify monitoring systems as required under this rule, the final rule establishes a monitoring certification deadline of 180 days after the effective date of the rule for affected units that are not already required to report emissions under 40 CFR part 75 under another program, equivalent to the 180-day window already provided to units commencing commercial operation after (or less than 180 days before) the final rule's effective date. The 180th day for units in this situation will likely fall after the end of the 2023 ozone season, with the result that the certification deadline will be extended until May 1, 2024, the first day of the 2024 ozone season. Because the Group 3 trading program's allowance holding requirements apply to a given unit only after that unit's monitor certification deadline, the units in this situation consequently will become subject to allowance holding requirements as of the 2024 ozone season rather than the 2023 ozone season.

The EPA received no comments on the provisions establishing a monitor certification deadline 180 days after the effective date of this rule for affected units that are not already required to report emissions under 40 CFR part 75, and the provisions are being finalized as proposed.

b. Additional Recordkeeping and Reporting Requirements

To facilitate implementation of the backstop daily NO_X emissions rates for certain coal-fired units, the secondary emissions limitations for units contributing to assurance level exceedances, and the revised default unit-level allowance allocation procedures, the final rule amends 40 CFR part 75 to establish two sets of additional recordkeeping and reporting requirements. The first set of additional recordkeeping and reporting requirements is specific to the backstop daily emissions rate provisions. Starting January 1, 2024, units listing coal as a fuel in their monitoring plans, serving generators of 100 MW or larger, and equipped with SCR controls on or before the end of the previous control period (except circulating fluidized bed units) will be required to record and report total daily NO_X emissions and total daily heat input, daily average NO_X emissions rate, and daily NO_X emissions exceeding the backstop daily NO_X emissions rate. The units will also be required to record and report cumulative NO_X emissions exceeding the backstop daily NO_X emissions rate for the ozone season and any portion of such cumulative NO_X emissions exceeding 50 tons. Starting January 1, 2030, the same recordkeeping and reporting requirements will apply to all units listing coal as a fuel in their monitoring plans and serving generators of 100 MW or larger (except circulating fluidized bed units), including units not equipped with SCR controls. These data will be used to determine the allowance surrender requirements related to the backstop daily NO_X emissions rates. Implementation of these additional recordkeeping and reporting requirements would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

The second type of additional recordkeeping and reporting requirements applies to units exhausting to common stacks. For these units, 40 CFR part 75 includes options that often allow monitoring to be conducted at the common stack on a combined basis for all the units as an alternative to installing separate monitoring systems for the individual units in the ductwork leading to the common stack. The units then keep records and report hourly and cumulative NO_X mass emissions and in many cases heat input data on a combined basis for all units exhausting to the common stack. With respect to heat input data, but not NO_X mass emissions data, most such units have also been required historically to record and report hourly and cumulative data on an individual-unit basis, and where necessary they typically have computed the necessary unit-level hourly heat input values by apportioning the combined hourly heat input values for the common stack in proportion to the individual units' recorded hourly output of electricity or steam. *See generally* 40 CFR 75.72.

In this rulemaking, the provisions governing default unit-level allowance allocations, backstop daily NO_X emissions rates for certain coal-fired units, and secondary emissions limitations for units contributing to assurance level exceedances all require the use of unit-level reported data on NO_X mass emissions (or unit-level NO_X emissions rates computed in part based on unit-level reported data on NO_X mass emissions). To facilitate the implementation of these provisions, the final rule requires all units covered by the Group 3 trading program exhausting to common stacks to record and report unit-level hourly and cumulative NO_X mass emissions data starting January 1, 2024. To obtain the necessary unit-level hourly mass emissions values, the revised regulations rule allow the units to apportion hourly mass emissions values determined at the common stack in proportion to the individual units' recorded hourly heat input. The apportionment procedure is very similar to the apportionment procedure that most such units already apply to compute reported unit-level heat input data. Where sources choose to obtain the additional required data values through apportionment, implementation of the additional recordkeeping and reporting requirements will necessitate a one-time update to the units' data acquisition and handling systems but will not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

For most units sharing common stacks, the EPA expects that the reported unit-specific hourly NO_X emissions values computed through the apportionment procedures will reasonably approximate the values that could be obtained through installation and operation of separate monitoring systems for the individual units, because the units exhausting to the common stack would be expected to have similar NO_X emissions rates. However, the EPA also recognizes that at some plants, particularly those where SCR-equipped and non-SCR-equipped coal-fired units share a common stack, unit-level values determined through apportionment based on electricity or steam output could overstate the reported NO_X mass emissions for the SCR-equipped units and correspondingly understate the reported NO_X mass emissions for the non-SCR-equipped units.[362] As proposed, the

[361] The units are listed in Table VI.B.3–1.

[362] The EPA is aware of five plants in the states covered by this rule where SCR-equipped and non-SCR-equipped coal-fired units exhaust to a common stack: Clifty Creek in Indiana; Cooper, Ghent, and Shawnee in Kentucky; and Sammis in Ohio. The owners of the Sammis plant have announced plans to retire the plant in 2023.

final rule leaves in place the existing options under 40 CFR part 75 for plants to upgrade their monitoring equipment to monitor on a unit-specific basis instead of at the common stack. Plant owners may find this option attractive if they believe it would reduce the quantities of reported emissions exceeding the backstop daily emissions rate.

The EPA is finalizing the additional recordkeeping and reporting requirements generally as proposed, with modifications as needed to accommodate the changes in the backstop daily emissions rate provisions from proposal discussed in sections VI.B.1.c.i and VI.B.1.7. No comments were received on the recordkeeping and reporting requirements added to facilitate implementation of the backstop daily emissions rate. Comments on the requirement to report unit-specific NO_X emissions data for units sharing common stacks are addressed in the following paragraphs.

Comment: Some commenters claimed that for plants where SCR-equipped and non-SCR-equipped coal-fired units share common stacks, the rule as proposed would have effectively mandated installation of unit-specific monitoring systems in order to comply with the backstop daily emissions rate provisions. The commenters generally requested that application of the backstop daily rate provisions be delayed for plants with common stacks until all units sharing the stacks were subject to the provisions. Alternatively, they claimed that the EPA should consider the cost of the additional unit-specific monitoring system to be a cost of the rule.

One commenter claimed that the option to install unit-specific monitoring systems for the units sharing a common stack at its plant was not feasible because of a lack of locations in the units' ductwork suitable for installation of the monitoring equipment. Specifically, the commenter claimed that EPA Method 1 requires monitoring equipment to be located at least eight duct diameters downstream and two duct diameters upstream of any flow disturbance and stated that the units had no straight runs of ductwork sufficiently long to meet these criteria.

Response: The EPA's response to comments about the application of backstop rate requirements to units sharing common stacks is in section VI.B.7 of this document. With respect to assertions that the rule effectively mandates installation of unit-specific monitoring systems, the EPA disagrees. Although the EPA pointed out the option in the proposal, anticipating that owners of some units sharing common stacks might find it advantageous to upgrade their monitoring systems, the final rule does not mandate such upgrades and explicitly provides a reporting option that can be used if a plant owner continues to monitor only at the common stack. For example, a plant owner might choose not to upgrade monitoring systems if the owner does not plan to operate the non-SCR-equipped units sharing the stack frequently. Regarding the contention that the cost of additional monitoring systems should be considered a cost of the rule, the EPA notes that the monitoring cost estimates that the Agency regularly develops for 40 CFR part 75 already reflect the conservative assumption that all affected units perform monitoring on a unit-specific basis.

With respect to the comment asserting an inability to install unit-specific monitoring equipment because of a lack of suitable locations, the EPA does not believe the commenter has provided sufficient information to support the assertion. Although the commenter cites the EPA Method 1 location criteria, the CEMS location provisions in 40 CFR part 75 do not reference those location criteria but instead reference the EPA Performance Specification 2 location criteria, which recommend that a CEMS be located at least two duct diameters downstream and a half duct diameter upstream from a point at which a change in pollutant concentration may occur.[363] Thus, while the commenter states that its units do not have straight runs of ductwork ten duct diameters long, the relevant siting criteria actually call for straight runs of ductwork only 2.5 duct diameters long, and the commenter has not provided information indicating that these criteria could not be met. Moreover, even EPA Method 1 does not require monitoring equipment to be located eight duct diameters upstream and two duct diameters downstream of any flow disturbance. While the method recommends those distances as the first option, the method also allows for locations two duct diameters upstream and a half duct diameter upstream from any flow disturbance, as well as other locations if certain performance criteria can be met.[364]

[363] Appendix B to 40 CFR part 60, Performance Specification 2, sec. 8.1.2; *see also* appendix A to 40 CFR part 75, section 1.1.

[364] Appendix A–1 to 40 CFR part 60, Method 1, sec. 11.1.

11. Designated Representative Requirements

As noted in section VI.B.1.a of this document, a core design element of all the CSAPR trading programs is the requirement that each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account. The necessary authorization of a designated representative is certified to the EPA in a certificate of representation.

The existing designated representative provisions in the Group 3 trading program regulations already provide that the EPA will interpret references to the Group 2 trading program in certain documents—including a certificate of representation as well as a notice of delegation to an agent or an application for a general account—as if the documents referenced the Group 3 trading program instead of the Group 2 trading program. For these reasons, sources that have participated in the Group 2 trading program and that are transitioning to the Group 3 trading program under this rule will not need to submit any new forms as part of the transition, because previously submitted forms will be valid for purposes of the Group 3 trading program.

For a source that is newly affected under the Group 3 trading program and that is not currently affected under the Group 2 trading program, a designated representative who has been duly authorized by the source's owners and operators must submit a new or updated certificate of representation to the EPA. The EPA will not record any Group 3 allowances allocated to a source in the source's compliance account until a certificate of representation has been submitted for the source. If a source is also affected under other CSAPR trading programs or the Acid Rain Program, the same individual must be the source's designated representative for purposes of all the programs.

The EPA did not propose and is not finalizing any changes to the designated representative requirements. The EPA received no comments on the provisions of the proposal relating to these requirements.

12. Transitional Provisions

This section discusses several provisions that the EPA will implement to address the transition of sources into the Group 3 trading program as revised. The purposes of the transitional provisions are generally the same as the purposes of the analogous transitional provisions promulgated in the Revised CSAPR Update: first, addressing the likelihood that the effective date of this rule will fall after the starting date of the first affected ozone season (which in this case is, May 1, 2023); second, establishing an appropriately-sized initial allowance bank through the conversion of previously banked allowances; and third, preserving the intended stringency of the Group 2 trading program for the sources that will continue to be subject to that program.[365] However, the sources that will be participants in the revised Group 3 trading program under this rule are transitioning from several different starting points—with some sources already in the existing Group 3 trading program, some sources coming from the Group 2 trading program, and some sources not currently participating in any seasonal NO_X trading program. The EPA is therefore finalizing transitional provisions that differ across the sets of potentially affected sources based on the sources' different starting points.

a. Prorating Emissions Budgets, Assurance Levels, and Unit-Level Allowance Allocations in the Event of an Effective Date After May 1, 2023

The EPA expects that the effective date of this rule will fall after the start of the Group 3 trading program's 2023 control period on May 1, 2023, because the effective date of the rule will be 60 days after the date of the final rule's publication in the **Federal Register**. The EPA is addressing this circumstance by determining the amounts of emissions budgets and unit-level allowance allocations on a full-season basis in the rulemaking and by also including provisions in the revised regulations to prorate the full-season amounts as needed to ensure that no sources become subject to new or more stringent regulatory requirements before the final rule's effective date.[366] Variability limits, assurance levels, and unit-level allocations for 2023 will all be computed using the appropriately prorated emissions budgets amounts.[367]

As discussed in section VI.B.2 of this document, in the case of the three states (and Indian country within the states' borders) whose sources do not currently participate in either the Group 2 trading program or the Group 3 trading program—Minnesota, Nevada, and Utah—the sources will begin participating in the Group 3 trading program on the later of May 1, 2023, or the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, and were therefore in effect for the entire 153-day control period from May 1, 2023, through September 30, 2023. Assuming that the final rule becomes effective after May 1, 2023, as expected, the EPA will determine prorated emissions budgets for the 2023 control period by multiplying each full-season emissions budget by the number of days from the rule's effective date through September 30, 2023, dividing by 153 days, and rounding to the nearest allowance. The prorated variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season (*i.e.,* May 1, 2023 through September 30, 2023) exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance, yielding prorated assurance levels that equal a minimum of 121 percent of the prorated emissions budgets. To determine unit-level allocation amounts from the prorated emissions budgets, the EPA will apply the unit-level allocation procedure described in section VI.B.9 to the prorated budgets. All calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the rule's effective date. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 3 trading program—Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—the sources will continue to participate in the Group 3 trading program for the 2023 control period, subject to prorating procedures designed to ensure that the changes in 2023 emissions budgets and assurance levels will not substantively affect the sources' requirements prior to the rule's effective date. For these states, in the rulemaking the EPA has computed the full-season emissions budgets that would have applied for the entire 2023 control period if the final rule had become effective no later than May 1, 2023, but the EPA has also retained in the regulations the full-season emissions budgets for the 2023 control period that were established in the Revised CSAPR Update rulemaking. The EPA has added a provision to the regulations indicating that the emissions budgets promulgated in the Revised CSAPR Update will apply on a prorated basis for the portion of the 2023 control period before the final rule's effective date and the emissions budgets established in this rulemaking will apply on a prorated basis for the portion of the 2023 control period on and after the final rule's effective date. Under this provision, the EPA will determine a blended emissions budget for each state for the 2023 control period, computed as the sum of the appropriately prorated amounts of the state's previous and revised emissions budgets. (For example, if the final rule becomes effective on the eleventh day of the 153-day 2023 control period, the blended emissions budget will equal the sum of 10/153 times the previous emissions budget plus 143/153 times the revised emissions budget, rounded to the nearest allowance.) Blended variability limits for the 2023 control period will be computed by first determining for each state the percentage by which the state's reported heat input for the full 2023 ozone season exceeds the heat input used to compute the state's full-season 2023 emissions budget under this rule and then multiplying the higher of this percentage or 21 percent by the state's prorated emissions budget and rounding to the nearest allowance,

[365] As discussed in section VI.B.1.d, the EPA is not creating a ''safety valve'' mechanism in this rule analogous to the voluntary supplemental allowance conversion mechanism established under the Revised CSAPR Update, but intends in the near future to propose and take comment on potential amendments to the Group 3 trading program that would add an auction mechanism to the regulations for the purpose of further increasing allowance market liquidity in conjunction with other appropriate changes to ensure program stringency is maintained. While these changes may provide an additional measure of assurance to the market that allowances will be available for compliance to a degree consistent with the Step 3 emissions control stringency, the EPA does not anticipate that market liquidity concerns pose a challenge to the feasibility of sources to comply with the Group 3 trading program as finalized in this action.

[366] As discussed in sections VI.B.7 and VI.B.8, the revisions establishing unit-specific backstop daily emissions rates and, for units contributing to assurance level exceedances, secondary unit-specific emissions limitations, will not take effect until the 2024 control period or later.

[367] The EPA notes that transitional provisions similar to the prorating provisions being finalized in this rule were finalized and implemented without issue under the Revised CSAPR Update.

yielding blended assurance levels that equal a minimum of 121 percent of the blended emissions budgets. Unit-level allocations will be determined by applying the allocation procedure described in section VI.B.9 to the blended budgets. Again, all calculations required to determine the prorated emissions budgets, the minimum 21 percent variability limits, and the unit-level allocations for the 2023 control period will be carried out as soon as possible after the EPA learns the effective date of this rule. The unit-level allocations for both the 2023 and 2024 control periods will be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in section VI.B.9.b of this document.

In the case of the states (and Indian country within the states' borders) whose sources currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin—the sources will begin to participate in the Group 3 trading program as of May 1, 2023, regardless of the rule's effective date, as discussed in section VI.B.2 of this document, subject to prorating procedures designed to ensure that the transition from the Group 2 trading program to the Group 3 trading program will not substantively affect the sources' requirements prior to the rule's effective date. The prorating procedures for these states mirror the procedures for the states currently in the Group 3 trading program, except that because no emissions budgets currently appear in the Group 3 trading program regulations for the states that are currently covered by the Group 2 trading program, the EPA has added two sets of emissions budgets for these states to the Group 3 trading program regulations: first, the states' emissions budgets for the 2023 control period that currently appear in the Group 2 trading program regulations, which are being included in the revised Group 3 trading program regulations to represent the states' emissions budgets for the portion of the 2023 control period before the rule's effective date, and second, the emissions budgets for the 2023 control period established for the states in this rulemaking, which are being included in the revised Group 3 trading program regulations to represent the state's emissions budgets for the portion of the 2023 control period on and after the rule's effective date. The procedures and timing for determining blended emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, as well as the timing for the recordation of unit-level allocations, are the same as for the states currently in the Group 3 trading program.

Beginning administrative implementation of the Group 3 trading program starting on May 1, 2023, for sources currently in the Group 2 trading program imposes no new or different requirements on these sources. It would serve the public interest and greatly aid in administrative efficiency for most elements of the Group 3 trading program—specifically, all elements of the trading program other than the elements designed to establish more stringent emissions limitations for the sources coming from the Group 2 trading program—to apply to the sources starting on May 1, 2023. This is how the EPA handled the earlier transition of twelve states from the Group 2 to the Group 3 trading program in the Revised CSAPR Update, which was accomplished successfully and without incident. *See* 86 FR 23133–34. This approach would facilitate implementation of the Group 3 trading program in an orderly manner for the entire 2023 ozone season and reduce compliance burdens and potential confusion. Each of the CSAPR trading programs for ozone season NO_X is designed to be implemented over an entire ozone season. Implementing the transition from the Group 2 trading program to the Group 3 trading program in a manner that required the covered sources to participate in the Group 2 trading program for part of the 2023 ozone season and the Group 3 trading program for the remainder of that ozone season would be complex and burdensome for sources. Attempting to address the issue by splitting the Group 2 and Group 3 requirements for these sources into separate years is not a viable approach, because the EPA has no legal basis for releasing the transitioning Group 2 sources from the emissions reduction requirements found to be necessary in the CSAPR Update for a portion of the 2023 ozone season, and the EPA similarly has no legal basis for deferring implementation of the 2023 emissions reduction requirements found to be necessary under this rule for the transitioning Group 2 sources until 2024. Moreover, the requirements of the current Group 2 trading program and the revised Group 3 trading program for the 2023 control period are substantively identical as to almost all provisions, such that with respect to those provisions, a source will not need to alter its operations in any manner or face different compliance obligations as a consequence of a transition from the Group 2 trading program to the Group 3 trading program. Thus, the EPA believes that no substantive concerns regarding retroactivity arise from transitioning the sources currently in the Group 2 trading program to the Group 3 trading program starting on May 1, 2023, as long as those aspects of the revised Group 3 trading program for the 2023 control period that *do* meaningfully differ from the analogous aspects of the Group 2 trading program—that is, the relative stringencies of the two trading programs, as reflected in the emissions budgets and associated assurance levels—are applied only as of the effective date of the final rule.

In all respects other than prorating the emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, with respect to the sources currently participating in the Group 2 trading program or the Group 3 trading program, the EPA will implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period. Thus, emissions will be monitored and reported for the entire 2023 ozone season (*i.e.,* May 1, 2023, through September 30, 2023), and as of the allowance transfer deadline for the 2023 control period (*i.e.,* June 1, 2024) each source will be required to hold in its compliance account vintage-year 2023 Group 3 allowances not less than the source's emissions of NO_X during the entire 2023 ozone season. Any efforts undertaken by one of these sources to reduce its emissions during the portion of the 2023 ozone season before the effective date of the rule will aid the source's compliance by reducing the amount of Group 3 allowances that the source would need to hold in its compliance account as of the allowance transfer deadline, increasing the range of options available to the source for meeting its compliance obligations under the revised Group 3 trading program.

In the case of the sources in the three states that do not currently participate in the Group 2 trading program or the Group 3 trading program, the 2023 control period will begin on the effective date of the rule, and because the effective date of the rule is expected to fall after May 1, 2023, the 2023 control period for the sources in these states will be shorter than the 153-day length of the 2023 control period for the sources in the remaining states. However, the EPA similarly will implement the revised Group 3 trading program for the sources in these states in a uniform manner for the entire shorter control period.

The prorating provisions are being finalized as proposed. The EPA received no comments on the portion of the proposal discussing these provisions.

b. Creation of Additional Group 3 Allowance Bank for 2023 Control Period

In the CSAPR Update, where the EPA established the Group 2 trading program and transitioned over 95 percent of the sources that had been participating in what is now the CSAPR NO_X Ozone Season Group 1 Trading Program (the ''Group 1 trading program'') to the new program, the EPA determined that it was reasonable to establish an initial bank of allowances for the Group 2 trading program by converting almost all allowances banked under the Group 1 trading program at a conversion ratio determined by a formula. In the Revised CSAPR Update, where the EPA established the Group 3 trading program and transitioned approximately 55 percent of the sources that had been participating in the Group 2 trading program to the new program, the EPA similarly determined that it was reasonable to provide for an initial bank of allowances for the Group 3 trading program by converting allowances banked under the Group 2 trading program at a conversion ratio determined by a formula, using a conversion procedure that was modified to leave much of the Group 2 allowance bank available for use by the approximately 45 percent of sources then in the Group 2 trading program that would remain in that program. Any conversion of banked allowances from a previous trading program for use in a new trading program must ensure that implementation of the new trading program will result in NO_X emissions reductions sufficient to address significant contribution by all states that would be participating in the new trading program, while also providing industry certainty (and obtaining an environmental benefit) through continued recognition of the value of saving allowances through early reductions in emissions. The EPA's approach to balancing these concerns in the CSAPR Update through the conversion of banked allowances from the Group 1 trading program to the Group 2 trading program was upheld in *Wisconsin* v. *EPA,* 938 F.3d at 321.

Under this final rule, applying the same balancing principle as in the CSAPR Update and the Revised CSAPR Update, the EPA will carry out a further conversion of allowances banked for control periods before 2023 under the Group 2 trading program into allowances usable in the Group 3 trading program in control periods in 2023 and later years. Because the EPA is transitioning over 80 percent of the remaining sources in the Group 2 trading program to the Group 3 trading program—much closer to the situation in the CSAPR Update than the situation in the Revised CSAPR Update—in this rule the EPA is applying a conversion procedure similar to the procedure followed in the CSAPR Update. Under the conversion procedure in this rule, the EPA has not set a predetermined conversion ratio in the regulations (as was done in the Revised CSAPR Update) but instead has established provisions identifying the target amount of new Group 3 allowances that will be created and defining the types of accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances (as was done in the CSAPR Update). The conversion date will be carried out by September 18, 2023, which is expected to be approximately 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and approximately ten months before the compliance deadline for the 2023 control period under the Group 3 trading program. The actual conversion ratio will be determined as of the conversion date and will be the ratio of the total amount of Group 2 allowances held in the identified types of accounts prior to the conversion to the total amount of Group 3 allowances being created.

With respect to the numerator of the conversion ratio—that is, the total amount of Group 2 allowances being converted—the EPA has defined the types of accounts included in the conversion to include all accounts except the facility accounts of sources in states that will remain in the Group 2 trading program, consistent with the approach taken in the CSAPR Update.[368] Thus, the accounts whose holdings of Group 2 allowances will be converted to Group 3 allowances will include (1) the facility accounts of all sources in the states transitioning from the Group 2 trading program to the Group 3 trading program, (2) the facility accounts of all sources in the states already participating in the Group 3 trading program, (3) the facility accounts of all sources in any other states not covered by the Group 2 trading program that happen to hold Group 2 allowances as of the conversion date, and (4) all general accounts (that is, accounts that are not facility accounts, including other accounts controlled by source owners as well as accounts controlled by non-source entities such as allowance brokers). Creating the new Group 3 allowances through conversion of previously banked Group 2 allowances will also help preserve the stringency of the Group 2 trading program for the states that remain covered by that trading program at levels consistent with the stringency found to be appropriate to address those states' good neighbor obligations with respect to the 2008 ozone NAAQS in the CSAPR Update.

With respect to the denominator of the conversion ratio—that is, the target amount of Group 3 allowances that will be created in the conversion process—the EPA has followed the same approach for setting the target amount that was used in the Revised CSAPR Update for creation of the initial Group 3 allowance bank. Specifically, the target amount of Group 3 allowances to be created in this rule will be computed as the sum of the minimum 21 percent variability limits for the 2024 control period[369] established for the ten states being added to the Group 3 trading program, prorated to reflect the portion of the 2023 control period occurring on and after the effective date of the final rule. Based on the amounts of the state emissions budgets and variability limits, the full-season target amount for the conversion would be 23,094 Group 3 allowances. The quantity of banked Group 2 allowances currently held in accounts other than the facility accounts of sources in Iowa, Kansas, and Tennessee exceeding the quantity of allowances likely to be needed for 2022 compliance is approximately 149,386 allowances. Thus, if the quantities of banked Group 2 allowances held in the accounts being included in the conversion do not change between now and the conversion date, and if there was no prorating adjustment, the conversion ratio would be approximately 6.5-to-1, meaning that one Group 3 allowance would be created for every 6.5 Group 2 allowances deducted in the conversion process.[370]

As noted in section VI.B.12.a of this document, the EPA expects that the effective date of this rule will occur after

[368] The states whose sources will continue to participate in the Group 2 trading program for the 2023 control period will be Iowa, Kansas, and Tennessee.

[369] Similar to the approach taken in the Revised CSAPR Update, because emissions reductions from some of the emissions controls that EPA has identified as appropriate to use in setting budgets are first reflected in the 2024 state budgets rather than the 2023 state budgets, the EPA is basing the bank target amount on the sum of the states' 2024 variability limits rather than the 2023 variability limits.

[370] By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

the start of the 2023 ozone season, and prorating provisions are being promulgated in this rule to ensure that the increased stringency of this rule's state budgets and state assurance levels (*i.e.,* the sums of the budgets and variability limits) will take effect only after the rule's effective date. Consistent with these other procedures, the EPA will similarly prorate the bank target amount used in the conversion process. For example, if the effective date of the final rule is the eleventh day of the 153-day 2023 ozone season, the full-season initial bank target amount of 23,094 allowances would be prorated to an initial bank target amount of 21,585 allowances.[371] The EPA notes that prorating the bank amount in this manner will not reduce sources' compliance flexibility for the 2023 ozone season, because the amounts of Group 3 allowances that sources will receive for the portion of the 2023 ozone season before the rule's effective date will be based on the trading program budgets for the 2023 control period that were in effect before this rulemaking. These trading program budgets exceed the sources' collective 2022 emissions by approximately 29,789 tons, indicating potentially surplus allowances roughly 1.3 times the full-season bank conversion target amount of 23,094 allowances. Thus, although the prorating procedure will reduce the amount of Group 3 allowances that would be available to sources in the form of an initial bank, the reduction in the quantity of these allowances will be more than offset by the quantities of Group 3 allowances that will be allocated in excess of sources' recent historical emissions levels for the portion of the ozone season before the final rule's effective date.

As in the CSAPR Update and the Revised CSAPR Update, the EPA's overall objective in establishing the target amount for the allowance conversion is to achieve a total target amount for the bank at a level high enough to accommodate year-to-year variability in operations and emissions, as reflected in states' variability limits, but not high enough to allow sources collectively to plan to emit in excess of the collective state budgets. The EPA believes that a well-established trading program should be able to function with an allowance bank lower than the full amount of the covered states' variability limits, as discussed in section VI.B.6 of this document with respect to the bank recalibration process that will begin with the 2024 control period. However, the EPA also believes there are several compelling reasons in this instance to use a bank target higher than the minimum practicable level.

First, making an allowance bank available for use in the 2023 control period that is somewhat higher than the minimum practicable level will help to address concerns that might otherwise arise regarding the transition to a new set of compliance requirements, for some sources, and the transition to compliance requirements based on revised emissions budgets different from the emissions budgets that the sources had reason to anticipate under previous rulemakings, for the remaining sources. Although the EPA is confident that the emissions budgets being established in this rulemaking for the 2023 control period are readily achievable, the EPA also believes that the existence of a somewhat larger allowance bank at this transition point will promote sources' confidence in their ability to meet their 2023 compliance obligations in general and in a liquid allowance market in particular. Second, because the large majority of the remaining Group 2 allowances that will be converted to Group 3 allowances in this rulemaking are held by the sources currently in the Group 2 trading program, while the large majority of the initial bank of Group 3 allowances previously created in the conversion under the Revised CSAPR Update are held by the sources already in the Group 3 trading program, basing the conversion in this rulemaking on a target bank amount set in the same manner as the target bank amount used in the Revised CSAPR Update is expected to result in a less concentrated distribution of holdings of banked Group 3 allowances following the conversion than would be the case if a more stringent target bank amount were used under this rulemaking than was used in the Revised CSAPR Update. A lower concentration of holdings of banked Group 3 allowances would generally be expected to help ensure allowance market liquidity. Third, the EPA considers it equitable to treat the sources in the states transitioning from the Group 2 trading program to the Group 3 trading program in this rulemaking roughly similarly to the sources in the states that transitioned between the same two trading programs in the Revised CSAPR Update with respect to the benefit they would receive under the Group 3 trading program for any efforts they may have made to make emissions reductions under the Group 2 trading program beyond the minimum efforts that were required to comply with the emissions budgets under that program. Finally, to the extent that the conversion results in a larger bank of allowances remaining after the 2023 control period than is considered necessary to sustain a well-functioning trading program in subsequent control periods, the excess will be removed from the program in the bank recalibration process that will be implemented starting with the 2024 control period and therefore will not weaken sources' incentives to control emissions on a permanent basis.

The rule's provisions relating to the creation of an incremental Group 3 allowance bank are being finalized as proposed. Comments on the creation of the incremental allowance bank are discussed in section 5 of the *RTC.*

c. Recall of Group 2 Allowances Allocated for Control Periods After 2022

To maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program, the EPA is recalling CSAPR NO_X Ozone Season Group 2 allowances equivalent in amount and usability to all vintage year 2023–2024 CSAPR NO_X Ozone Season Group 2 allowances previously allocated to sources in states and areas of Indian country transitioning to the Group 3 trading program and recorded in the sources' compliance accounts. The recall provisions apply to all sources in jurisdictions newly added to the Group 3 trading program in whose compliance accounts CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2023 or 2024 were recorded, including sources where some or all units have permanently retired or where the previously recorded 2023–2024 allowances have been transferred out of the compliance account. The recall provisions provide a flexible compliance schedule intended to accommodate any sources that have already transferred the previously recorded 2023–2024 allowances out of their compliance accounts and allow Group 2 allowances of earlier vintages to be surrendered to achieve compliance. Like the similar recall provisions finalized in the Revised CSAPR Update, the recall provisions include specifications for how the recall provisions apply in instances where a source and its allowances have been transferred to different parties and for the procedures that the EPA will follow to implement the recall.

Under the Group 2 trading program regulations, each Group 2 allowance is a ''limited authorization to emit one ton of NO_X during the control period in one year,'' where the relevant limitations include the EPA Administrator's

[371] $23{,}094 \times (153 - 10) \div 153 = 21{,}585$.

authority ''to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' 40 CFR 97.806(c)(6)(ii). The Administrator is determining that, to effectively implement the Group 2 trading program as a compliance mechanism through which states not subject to the Group 3 trading program may continue to meet their obligations under CAA section 110(a)(2)(D)(i)(I) with regard to the 2008 ozone NAAQS, it is necessary to limit the use of Group 2 allowances equivalent in quantity and usability to all Group 2 allowances previously allocated for the 2023–2024 control periods and recorded in the compliance accounts of sources in the newly added Group 3 jurisdictions. The Group 2 allowances that have already been allocated to sources in the newly added Group 3 states for the 2023–2024 control periods and recorded in the sources' compliance accounts represent the substantial majority of the total remaining quantity of Group 2 allowances that have been allocated and recorded for the 2023–2024 control periods and that were not already made subject to recall when other jurisdictions were transferred from the Group 2 trading program to the Group 3 trading program in the Revised CSAPR Update. Because allowances can be freely traded, if the use of the 2023–2024 Group 2 allowances previously recorded in newly added Group 3 sources' compliance accounts (or equivalent Group 2 allowances) were not limited, the effect would be the same as if the EPA had issued to sources in the states that will remain covered by the Group 2 trading program a quantity of allowances available for compliance under the 2023–2024 control periods many times the levels that the EPA determined to be appropriate emissions budgets for these states in the CSAPR Update. Through the use of banked allowances, the excess Group 2 allowances would affect compliance under the Group 2 trading program in control periods after 2024 as well. Continued implementation of the Group 2 trading program at levels of stringency consistent with the levels contemplated under the CSAPR Update therefore requires that the EPA limit the use of the excess allowances, as the EPA is doing through the recall provisions.

In this rule, the EPA is implementing limitations on the use of the excess 2023–2024 Group 2 allowances through requirements to surrender, for each 2023–2024 Group 2 allowance recorded in a newly added Group 3 source's compliance account, one Group 2 allowance of equivalent usability under the Group 2 trading program. The surrender requirements apply to the owners and operators of the Group 3 sources in whose compliance account the excess 2023–2024 Group 2 allowances were initially recorded. In general, each source's current owners and operators are required to comply with the surrender requirements for the source by ensuring that sufficient allowances to complete the deductions are available in the source's compliance account by one of two possible deadlines discussed later in this section. However, an exception is provided if a source's current owners and operators obtained ownership and operational control of the source in a transaction that did not include rights to direct the use and transfer of some or all of the 2023–2024 Group 2 allowances allocated and recorded (either before or after that transaction) in the source's compliance account. The rule provides that in such a circumstance, with respect to the 2023–2024 Group 2 allowances for which rights were not included in the transaction, the surrender requirements apply to the most recent former owners and operators of the source before any such transactions occurred. Because in this situation a source's former owners and operators might lack the ability to access the source's compliance account for purposes of complying with the surrender requirements, the former owners and operators would instead be allowed to meet the surrender requirements with Group 2 allowances held in a general account.[372]

To provide as much flexibility as possible consistent with the need to limit the use of the excess Group 2 allowances, for each 2023–2024 Group 2 allowance recorded in a Group 3 source's compliance account, the EPA will accept the surrender of either the same specific 2023–2024 Group 2 allowance or any other Group 2 allowance with equivalent (or greater) usability under the Group 2 trading program. Thus, a surrender requirement with regard to a Group 2 allowance allocated for the 2023 control period could be met through the surrender of any Group 2 allowance allocated for the 2023 control period or the control period in any earlier year—in other words, any 2017–2023 Group 2 allowance.[373] Similarly, the surrender requirement with regard to a 2024 Group 2 allowance could be met through the surrender of any 2017–2024 Group 2 allowance.

Owners and operators subject to the surrender requirements can choose from two possible deadlines for meeting the requirements. The optional first deadline will be 15 days after the effective date of this rule.[374] As soon as practicable or after this date, the EPA will make a first attempt to complete the deductions of Group 2 allowances required for each Group 3 source from the source's compliance account. The EPA will deduct Group 2 allowances first to address any surrender requirements for the 2023 control period and then to address any surrender requirements for the 2024 control period. When deducting Group 2 allowances to address the surrender requirements for each control period, EPA will first deduct allowances allocated for that control period and then will deduct allowances allocated for each successively earlier control period. This order of deductions is intended to ensure that whatever Group 2 allowances are available in the account are applied to the surrender requirements in a manner that both maximizes the extent to which all of the source's surrender requirements will be met and also ensures that any Group 2 allowances left in the source's compliance account after completion of all required deductions will be the earliest allocated, and therefore most useful, Group 2 allowances possible. Among the Group 2 allowances allocated for a given control period, The EPA will first deduct allowances that were initially recorded in that account, in the order of recordation, and will then deduct allowances that were transferred into that account after having been initially recorded in some other account, in the order of recordation.

Following the first attempt to deduct Group 2 allowances to address Group 3 sources' surrender requirements, the

[372] The EPA is currently unaware of any source that would need to use this flexibility but has included the option in the rule to address the theoretical possibility of such a situation.

[373] The first control period for the Group 2 trading program was in 2017.

[374] As discussed later in this section and in section VI.B.9.b, the EPA has conditioned recordation of any allocations of Group 3 allowances in a source's compliance account on the source's prior compliance with the recall requirements for Group 2 allowances. The purpose of providing an optional first deadline for the recall provisions 15 days after a final rule's effective is to ensure that sources have an early opportunity to comply with the recall provisions to be eligible to have allocations of Group 3 allowances recorded in their accounts 30 days after the final rule's effective date. Because the vast majority of sources subject to the recall provisions already hold sufficient Group 2 allowances to comply with the recall provisions, the EPA anticipates that the sources will easily be able to comply with the optional first recall deadline.

EPA will send a notification to the designated representative for each such source (as well as any alternate designated representative) indicating whether all required deductions were completed and, if not, the additional amounts of Group 2 allowances usable in the 2023 or 2024 control periods that must be held in the appropriate account by the second surrender deadline of September 15, 2023. Each notification will be sent to the email addresses most recently provided to the EPA for the recipients and will include information on how to contact the EPA with any questions. The EPA has provided that no allocations of Group 3 allowances will be recorded in a source's compliance account until all the source's surrender requirements with regard to 2023–2024 Group 2 allowances have been met. For this reason, the principal consequence to a source of failure to fully comply with the surrender requirements by 15 days after the effective date of this rule will be that any Group 3 allowances allocated to the units at the source for the 2023 and 2024 control periods that would otherwise have been recorded in the source's compliance account by 30 days after the effective date of a final rule will not be recorded as of that recordation date.

If all surrender requirements of 2023–2024 Group 2 allowances for a source have not been met in EPA's first attempt, the EPA will make a second attempt to complete the required deductions from the source's compliance account (or from a specified general account, in the limited circumstance noted previously) as soon as practicable on or after September 15, 2023. The order in which Group 2 allowances are deducted will be the same as described previously for the first attempt.

If the second attempt to deduct Group 2 allowances to meet the surrender requirements through deductions from the source's compliance account (or from a specified general account) is unsuccessful for a given source, as soon as practicable on or after November 15, 2023, to the extent necessary to address the unsatisfied surrender requirements for the source, the EPA will deduct the 2023–2024 Group 2 allowances that were initially recorded in the source's compliance account from whatever accounts the allowances are held in as of the date of the deduction, except for any allowances where, as of April 30, 2022, no person with an ownership interest in the allowances was an owner or operator of the source, was a direct or indirect parent or subsidiary of an owner or operator of the source, or was directly or indirectly under common ownership with an owner or operator of the source.[375] Before making any deduction under this provision, the EPA will send a notification to the authorized account representative for the account in which the allowance is held and will provide an opportunity for submission of objections concerning the data upon which the EPA is relying. In EPA's view, this provision does not unduly interfere with the legitimate expectations of participants in the allowance markets because the provision will not be invoked in the case of any allowance that was transferred to an independent party in an arms-length transaction before EPA's intent to recall 2023–2024 Group 2 allowances became widely known. The provision would apply only to a Group 2 allowance that, as of April 30, 2022, was still controlled either by the owners and operators of the source in whose compliance account it was initially recorded or by an entity affiliated with such an owner or operator. The EPA believes that by April 30, 2022, all market participants had ample opportunity to become informed of the proposed rule provisions to recall 2023–2024 Group 2 allowances recorded in Group 3 sources' compliance accounts, particularly since the EPA implemented a closely analogous recall of Group 2 allowances in the Revised CSAPR Update.[376]

The final revised regulations provide that failure of a source's owners and operators to comply with the surrender requirements will be subject to possible enforcement as a violation of the CAA, with each allowance and each day of the control period constituting a separate violation.

To eliminate any possible uncertainty regarding the amounts of Group 2 allowances allocated for the 2023–2024 control periods (or earlier control periods) that the owners and operators of each Group 3 source are required to surrender under the recall provisions, the EPA has prepared a list of the sources in the additional Group 3 states and areas of Indian country in whose compliance accounts allocations of 2023–2024 Group 2 allowances were recorded, with the amounts of the allocations recorded in each such compliance account for the 2023 and 2024 control periods. An additional list shows, for each newly added Group 3 source, the specific Group 2 allowances (batched by serial number) allocated for each control period and recorded in the source's compliance account and indicates whether, as of April 30, 2022, that batch of allowances was held in the source's compliance account, in an account believed to be partially or fully controlled by a related party (*i.e.,* an owner or operator of the source or an affiliate of an owner or operator of the source), or in an account believed to be fully controlled by independent parties. The lists are in a spreadsheet titled, ''Recall of Additional CSAPR NO_X Ozone Season Group 2 Allowances,'' available in the docket for this rule. After the first and second surrender deadlines, the EPA intends to update the lists to indicate for each Group 3 source whether the surrender requirements for the source under the recall provisions have been fully satisfied. The EPA will post the updated lists on a publicly accessible website to ensure that all market participants have the ability to determine which specific 2023–2024 Group 2 allowances initially recorded in any given Group 3 source's compliance account do or do not remain subject to potential deduction to address the source's surrender requirements under the recall provisions.

The recall provisions have been finalized without change from the proposal. The EPA received no comments on the proposed provisions.

13. Conforming Revisions to Regulations for Other CSAPR Trading Programs

As noted in section VI.B.1.a of this document, in addition to the Group 3 trading program, EPA currently administers five other CSAPR trading programs, all of which have provisions that in most respects parallel the provisions of the Group 3 trading program.[377] In this rulemaking, in addition to the revisions to the Group 3 trading program, the EPA is finalizing a set of conforming revisions that concern how various areas of Indian country are

[375] The provision under which the EPA will not deduct Group 2 allowances transferred to unrelated parties before April 30, 2022 from the transferees' accounts does not relieve the source to which the Group 2 allowances were originally allocated from the obligation to comply with the recall requirements. Specifically, the source would be required to comply with the recall requirements by obtaining and surrendering other Group 2 allowances.

[376] Even before publication of the proposed rule, the EPA posted information on its websites to notify market participants that a pending rulemaking could have consequences for the value and usability of Group 2 allowances. The posted locations included the electronic portal that authorized account representatives use to enter allowance transfers for recordation by the EPA in the Allowance Management System. Additionally, the EPA emailed a notice identifying the possibility of such consequences to the representatives for all Allowance Management System accounts.

[377] The regulations for the Group 3 Trading Program are at 40 CFR part 97, subpart GGGGG. The regulations for the other five CSAPR trading programs are at 40 CFR part 97, subparts AAAAA, BBBBB, CCCCC, DDDDD, and EEEEE.

treated for purposes of the allowance allocation provisions of the regulations for all the CSAPR trading programs.[378]

As discussed in section VI.B.9.a of this document, to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area, the EPA is revising the allowance allocation provisions in the Group 3 trading program regulations so that, instead of distinguishing between the sets of units within a given state's borders that either are not or are in Indian country, the revised regulations distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. For the same reasons stated in section VI.B.9.a of this document for the Group 3 trading program, the EPA is revising the allowance allocation provisions in the regulations for all the other CSAPR trading programs establishing the same substantive distinction among the sets of units within each state's borders. The specific regulatory provisions that are affected are identified in section IX.D of this document. The EPA is unaware of any currently operating units that would be affected by this revision to the regulations for the other CSAPR trading programs.

The conforming revisions to the regulations for the other CSAPR trading programs concerning Indian country are being finalized as proposed with no changes. The EPA received no comments on this portion of the proposal.

C. Regulatory Requirements for Stationary Industrial Sources

The EPA is finalizing FIPs with requirements for certain non-EGU industry sources for 20 of the states covered in this final rule. See section II.B of this document for the list of states. The FIPs include new emissions limitations for units in nine non-EGU industries that the EPA finds (as discussed in sections IV and V of this final rule) are significantly contributing to nonattainment or interfering with maintenance in other states. The emissions control requirements of these FIPs for non-EGU sources apply only during the ozone season (May through September) each year, beginning in 2026.

To achieve the necessary non-EGU emissions reductions for these 20 states, the EPA is finalizing the proposed emissions limitations with some adjustments as a result of information received during the public comment period. The final emissions limits apply to the most impactful types of units in the relevant industries and are achievable with the control technologies identified in this preamble and further discussed in the Final Non-EGU Sectors TSD. The non-EGU regulatory requirements unique to each industry that EPA is finalizing after considering public comments are discussed in sections VI.C.1 through VI.C.6 of this document.

These final FIP requirements apply to both new and existing emissions units. The non-EGU emissions limits and compliance requirements will apply in all 20 states (and, as discussed in section III.C.2 of this document, in areas of Indian country within the borders of those states), even if some of those states do not currently have emissions units in a particular source category. This approach is consistent with the approach that the EPA proposed, and the EPA did not receive any comments specifically objecting to our proposal to regulate new units. This approach will ensure that all new sources constructed in any of the 20 states will be subject to the same good neighbor requirements that apply to existing units under this final rule. This will also avoid creating incentives to move production from an existing non-EGU source to a new non-EGU source of the same type but lacking the relevant emissions control requirements either within a linked state or in another linked state.

Comment: The EPA received several comments regarding the proposed approach of establishing unit-specific emissions limitations for non-EGUs instead of an emissions trading program. Some commenters suggested that a trading program for non-EGUs could provide for operational flexibility and that EPA should allow sources to work with regulatory authorities to develop a trading program. Other commenters generally supported EPA's proposed approach and the decision to not include non-EGUs in an emissions trading program, because the EPA would not need to require sources to unnecessarily install CEMS. Commenters from several states and industry groups generally supported other monitoring options over CEMS, such as parametric monitoring, performance testing, and predictive emissions monitoring systems (PEMS). Additional commenters voiced concern with the expense and burden of continuous parametric monitoring and semi-annual performance tests. Specifically, commenters explained that semi-annual testing should not be required when the emissions limits only apply during the ozone season. Commenters also noted that many non-EGU boilers have recently been relieved from meeting the CEMS requirements under the 1998 NO_X SIP Call and that implementing CEMS on many of the non-EGU sources would be difficult and unnecessary.

Response: The EPA is finalizing a unit-specific approach with rate-based emissions limitations set on a uniform basis for the different segments of non-EGU emissions units using applicability criteria based on size and type of unit and, in some cases, emissions thresholds. In response to public comments, the EPA has adjusted these requirements as necessary to ensure that the emissions control requirements are achievable while ensuring that the FIPs achieve the necessary emissions reductions from the covered units to eliminate significant contribution to nonattainment and interference with maintenance as discussed in section V of this document. The EPA has concluded that a unit-specific approach is more appropriate for non-EGUs at this time than implementing a trading program and requiring all units to implement rigorous part 75 monitoring and reporting requirements. As explained in the proposal, to be considered for a trading program, non-EGU sources would have to comply with requirements for monitoring and reporting of hourly mass emissions in accordance with 40 CFR part 75 as we have required for all previous trading programs. Monitoring and reporting under part 75 include CEMS (or an approved alternative method), rigorous initial certification testing, and periodic quality assurance testing thereafter, such as relative accuracy test audits and daily calibrations. Consistent and accurate measurement of emissions is necessary to ensure that each allowance actually represents one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton of reported emissions from another source. *See* 75 FR 45325 (August 2, 2010). Moreover, these monitoring requirements generally would need to be in place for at least

[378] Additional conforming revisions concerning the schedules for the EPA to record allowance allocations in source's compliance accounts and for states to submit state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

one full ozone season to establish baseline data before it would be appropriate to rely on a trading program as the mechanism to achieve the required emissions reductions. Many industry and state commenters provided information confirming that many non-EGU units subject to this rulemaking do not currently utilize CEMS and specifically requested that EPA avoid requiring CEMS for all non-EGU industries. The EPA generally agrees that CEMS is not necessary for all non-EGU industries under the approach of this final rule and is finalizing other continuous monitoring, recordkeeping, and reporting requirements, as appropriate, that are specific to each non-EGU industry. The EPA has determined that establishing unit-specific emissions limitations for non-EGUs is a preferable approach in part because it avoids the rigorous monitoring requirements that would be applied to non-EGUs for the first time under a trading program.

Furthermore, to address commenters' concerns regarding non-EGU requirements for performance testing on a semi-annual basis, the EPA has also reduced the frequency of all required performance testing for non-EGU sources to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to demonstrate continuous compliance during the ozone season. The EPA also agrees with commenters that the annual testing requirements need not occur during the ozone season.

In addition, the EPA is modifying the applicability criteria and other regulatory requirements in response to public comments to provide certain compliance flexibilities for non-EGU industries where appropriate. As discussed further in section V.C.1 of this document, the EPA is modifying the requirements for Pipeline Transportation of Natural Gas by finalizing an exemption for emergency engines and allowing any owner or operator of an affected unit to propose a ''Facility-Wide Averaging Plan'' that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. Further, as discussed in section VI.C.5 of this document, the EPA is finalizing a low-use exemption for non-EGU boilers that operates less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. These final rule provisions require controls on the most impactful non-EGU industrial sources while providing the flexibility needed to accommodate unique circumstances on a case-by-case basis.

Comment: Commenters from several non-EGU industries and states raised general concerns regarding the ability for all sources to comply with the proposed emissions limits. Some commenters suggested that the EPA allow for case-by-case limits where necessary, similar to case-by-case RACT determinations. Specifically, commenters operating boilers, furnaces, and MWCs provided general explanations of how some units might not be able to meet the proposed emissions limits and requested that EPA provide for compliance flexibility where a source can demonstrate technical and economical infeasibility.

Response: As explained more in sections VI.C.1 through VI.C.6, the EPA has made several adjustments to the proposed applicability criteria, emissions limits, and compliance requirements in response to public comments and to reduce the costs of compliance with the final rule. For Pipeline Transportation and Natural Gas, the EPA is finalizing emissions averaging provisions and exemptions for emergency engines to allow facilities to avoid installing controls on units with lower actual emissions where the installation of controls would be less cost effective compared to higher-emitting units. For Cement and Concrete Product Manufacturing, the EPA has removed the daily source cap that would have resulted in an artificially restrictive NO_X emissions limit for affected cement kilns that have operated at lower levels due to the COVID–19 pandemic. For Iron and Steel and Ferroalloy Manufacturing, the EPA is finalizing a ''test-and-set'' requirement for reheat furnaces that will require the installation of low-NO_X burners or equivalent technology. The EPA has addressed the economic concerns raised by commenters regarding installation of controls at Iron and Steel facilities by not finalizing the other ten proposed emissions limits that were intended to require the installation of SCR at these facilities. For Glass and Glass Product Manufacturing, the EPA is finalizing alternative standards that apply during startup, shutdown, and idling conditions. For boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and the Iron and Steel Industry, the EPA is finalizing a low-use exemption to eliminate the need to install controls on boilers that would have resulted in relatively small reductions in emissions. Finally, the EPA has modified the monitoring and recordkeeping requirements for all non-EGU industries where possible to reduce the testing frequency to once a year and to provide for alternative monitoring protocols where appropriate, which should further reduce the costs of compliance on non-EGU sources. With these modifications to the final rule in response to comments, the non-EGU sources subject to this rule should be able to meet the applicable control requirements established in this final rule.

The EPA also recognizes, however, that there may be unique circumstances the Agency cannot anticipate that would, for a particular source, render the final emissions control requirements technically impossible or impossible without extreme economic hardship. To address these limited circumstances, the EPA is finalizing a provision that allows a source to request EPA approval of a case-by-case emissions limit based on a showing that an emissions unit cannot meet the applicable standard due to technical impossibility or extreme economic hardship. The EPA has modeled the case-by-case emissions limit mechanism on case-by-case RACT requirements and certain facility-specific emissions limits under 40 CFR part 60 identified by commenters.[379] The owner or operator of a source seeking a case-by-case emissions limit must submit a request meeting specific requirements to the EPA by August 5, 2024, one year after the effective date of this final rule. The applicable emissions limits established in this final rule remain in effect until the EPA approves a source's request for a case-by-case emissions limit. Given the May 1, 2026 compliance date that generally applies to all affected units in the non-EGU industries covered by this final rule, we encourage owners and operators of affected units who believe they must seek case-by-case emissions limits to submit their requests to the EPA before the one-year deadline for such requests, if possible, to ensure adequate time for EPA review and to install the necessary controls.

For a source requesting a case-by-case limit due to technical impossibility, the final rule requires that the request include emissions data obtained through CEMS or stack tests, an analysis

[379] For examples of case-by-case RACT provisions and source specific limits for boilers in subpart Db of the EPA's NSPS, see 40 CFR 60.44b(f); Regulations of Connecticut State Agencies section 22a–174–22e; Code of Maryland Regulations section 26.11.09.08(B)(3); and Code of Maine Rules section 096–138–3, subsection (I).

of all available control technologies based on an engineering assessment by a professional engineer or data from a representative sample of similar sources, and a recommendation concerning the most stringent emissions limit the source can technically achieve.

For a source requesting a case-by-case limit on the basis of extreme economic hardship, the final rule requires that the request include at least three vendor estimates from three separate vendors that do not have a corporate or business-affiliation with the source of the costs of installing the control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of compliance with the applicable emissions limit for that particular source would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry under this rule. In evaluating a source's request for a case-by-case limit due to extreme economic hardship, the EPA will consider the emissions reductions and costs identified in this final rulemaking (and related support documents) for other sources in the relevant industry and whether the costs of compliance for the source seeking the case-by-case limit would significantly exceed the highest representative end of the range of estimated cost-per-ton figures identified for any source in the relevant industry as discussed in section V of this document.

As discussed in section VI.A of this document, in *Wisconsin* the court held that some deviation from the CAA's mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity,'' *e.g.,* when compliance with the statutory mandate amounts to an impossibility.[380] Given these directives, the EPA cannot allow a covered source to avoid complying with the emissions limits established in this final rule unless the source can demonstrate that compliance with the limit would either be impossible as a technical matter or result in an extreme economic hardship—*i.e.,* exceed the high end of the cost-effectiveness estimates that informed the EPA's Step 3 determination of significant contribution, as discussed in section V of this document. The criteria that must be met to qualify for a case-by-case limit are designed to meet this statutory mandate.

Comment: Several commenters raised concerns about the EPA's differing applicability criteria for the various non-EGU industries. Specifically, the commenters questioned why EPA set applicability criteria for engines in Pipeline Transportation of Natural Gas and non-EGU boilers based on design capacity instead of potential to emit (PTE). Commenters also requested that the EPA allow each non-EGU category to rely on operating permits or other federally enforceable instruments to avoid being subject to the rule, such as limits to the PTE or limits on fuels used.

Response: The 100 tpy PTE threshold and comparable design capacity thresholds of 1,000 horsepower (hp) for engines and 100 mmBtu/hr for boilers are appropriate to ensure that the final rule reduces emissions from the most impactful units. The EPA finds the control technologies assumed to be installed to meet the final emissions limits would not be as readily available or cost effective for emissions units with PTE or design capacities lower than the applicability thresholds in this final rule.

With regard to the selection of design capacity thresholds for boilers and engines, the EPA finds that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines and boilers based on design capacity rather than PTE. We further explain our basis for establishing applicability thresholds based on design capacity for these two source categories in sections VI.C.1. and VI.C.5. For consistency with preexisting requirements for engines and boilers and to capture the sizes of units identified in Step 3 of our analysis, the EPA selected design capacities of 1,000 hp for engines and 100 mmBtu/hr for boilers. The EPA recognizes that these applicability thresholds captured more units than the EPA intended, particularly some low-use units. Therefore, as explained in sections VI.C.1 and VI.C.5., the EPA is establishing exemptions for low-use boilers and emergency engines, as well as new emissions averaging provisions for engines, to ensure that this final rule focuses on larger, more impactful units.

The EPA also agrees with commenters that the applicability criteria should allow for sources to rely on enforceable requirements that limit a source's PTE and is finalizing a regulatory definition of PTE that is generally consistent with the definitions of that term in the EPA's title V and NSR permit programs. *See, e.g.,* 40 CFR 51.165(a)(1)(iii), 70.2. In constructing the list of potential sources subject to the final rule, the EPA relied on available information to identify the PTE of the emissions units in the various non-EGU industries that are captured by the applicability criteria. *See Memo to Docket titled Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs.* Thus, the EPA's Step 3 analysis takes into account available information about currently enforceable emissions limits and physical and operational limitations identified in existing permits. The EPA finds it necessary to define PTE consistent with its use in the title V and NSR permit programs to ensure that the requirements of the final FIPs apply to the most impactful units identified in Step 3 of our analysis. However, to ensure that these FIPs achieve the emissions reductions necessary to eliminate significant contribution or interference with maintenance as described in this final rule, the applicability criteria for the Cement and Concrete Manufacturing, Iron and Steel and Ferroalloy Manufacturing, and Glass and Glass Product Manufacturing industries take into account only those enforceable PTE limits in effect as of the effective date of this final rule. Thus, any emissions unit in these three industries that has a PTE equal to or greater than 100 tons per year and thus meets the definition of an ''affected unit'' as of August 4, 2023, will remain subject to the applicable FIPs, without regard to any PTE limit that the emissions unit may subsequently become subject to. Each affected unit in these three industries must submit an initial notification of applicability to the EPA by December 4, 2023, that identifies its PTE as of the effective date of this final rule. Additionally, any owner or operator of an existing emissions unit that is not an affected unit as of August 4, 2023, but subsequently meets the applicability criteria (*e.g.,* due to a change in fuel use that increases the unit's PTE) will become an affected unit subject to the applicable requirements of this final rule at that time.

Comment: In responding to the EPA's request for comment on whether some non-EGU units would need to run controls required by the final FIP year-round, one commenter anticipated that control equipment would be operated as necessary to achieve applicable emissions limits, but that operational

[380] *Wisconsin,* 938 F.3d at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

flexibility, cost considerations and equipment longevity would warrant operation of certain control equipment on a schedule such that the equipment would not be used when unnecessary to meet emissions limits and/or outside of ozone season (*i.e.,* during winter months). The commenter further explained that flexibility in the operation of certain control equipment when unnecessary to meet emissions limits will allow for routine maintenance and repairs without requiring variances or similar exemptions from continuous operation requirements.

Response: Based on the feedback received during the public comment period, the EPA is finalizing requirements for non-EGU sources that will apply only during the ozone season, which runs annually from May to September. As discussed in the proposed rule, this is consistent with EPA's prior practice in Federal actions to eliminate significant contribution of ozone in the 1998 NO_X SIP Call, CAIR, CSAPR, CSAPR Update, and the Revised CSAPR Update. In addition, the EPA did not receive any information during the public comment period suggesting that sources would have to run the necessary controls year-round due to the nature of those controls. We note, however, that certain emissions-control technologies, such as combustion controls that are integrated into the unit itself, would likely function to reduce NO_X emissions year-round as a practical engineering matter.

Comment: Regarding electronic reporting through the Compliance and Emissions Data Reporting Interface (CEDRI), one commenter requested that CEDRI reporting requirements be consolidated in one location rather than repeated in each section. Another commenter requested that EPA include electronic reporting requirements for MWCs and specifically require that MWCs report CEMS data to CEDRI. Another commenter requested that EPA allow for extensions of time for electronic reports due to technical glitches.

Response: To increase the ease and efficiency of data submittal and data accessibility, the EPA is finalizing, as proposed, a requirement that owners and operators of non-EGU sources subject to the final FIPs, including MWCs, submit electronic copies of required initial notifications of applicability, performance test reports, performance evaluation reports, quarterly and semi-annual reports, and excess emissions reports through EPA's Central Data Exchange (CDX) using the CEDRI. The final rule requires that performance test results collected using test methods that are supported by the EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [381] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the XML schema on the ERT website and that other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, the EPA is finalizing a requirement that performance evaluation results of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the ERT at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the XML schema on the ERT website, and a requirement that other performance evaluation results be submitted in PDF using the attachment module of the ERT. The final rule also requires that initial notifications of applicability, annual compliance reports, and excess emissions reports be submitted in PDF uploaded in CEDRI.

Furthermore, the EPA is finalizing, as proposed, provisions that allow owners and operators to seek extensions of time to submit electronic reports due to circumstances beyond the control of the owner or operator (*e.g.,* due to a possible outage in CDX or CEDRI or a *force majeure* event) in the time just prior to a report's due date, as well as provisions specifying how to submit such a claim. Public commenters supported these proposed provisions.

The EPA agrees with commenters that the CEDRI reporting requirements could be centralized and has moved the CEDRI reporting requirements to 40 CFR 52.40.

1. Pipeline Transportation of Natural Gas

Applicability

The EPA is finalizing regulatory requirements for the Pipeline Transportation of Natural Gas industry that apply to stationary, natural gas-fired, spark ignited reciprocating internal combustion engines (''stationary SI engines'') within these facilities that have a maximum rated capacity of 1,000 hp or greater. Based on our review of the potential emissions from stationary SI engines, we find that use of a maximum rated capacity of 1,000 hp reasonably approximates the 100 tpy PTE threshold used in the *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026,* as described in section V.B of this document.

The EPA is also modifying certain provisions in response to public comments to provide compliance flexibilities for the Pipeline Transportation of Natural Gas industry sector in order to focus emissions reduction efforts on the highest emitting units. Specifically, the EPA is finalizing an exemption for emergency engines, and establishing provisions that allow any owner or operator of an affected unit to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule.

For purposes of this rule, the EPA is clarifying and narrowing the definition of ''pipeline transportation of natural gas'' to mean the transport or storage of natural gas prior to delivery to a local distribution company custody transfer station or to a final end-user (if there is no local distribution company custody transfer station). The revised definition of this term in § 52.41(a) is consistent with the EPA's regulatory definition of ''natural gas transmission and storage segment'' in 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015).

The EPA is also adding definitions of the terms ''local distribution company'' and ''local distribution company custody transfer station'' that are consistent with the definitions found in 40 CFR 98.400 (subpart NN, Suppliers of Natural Gas and Natural Gas Liquids) and 40 CFR 60.5430(a) (subpart OOOOa, Standards of Performance for Crude Oil and Natural Gas Facilities for Which Construction, Modification, or Reconstruction Commenced After September 18, 2015), respectively.

Comment: Several commenters asked EPA to exclude emergency engines in the final rule and one commenter recommended that the EPA revise the definition of affected unit to specifically exempt emergency engines. Commenters stated that doing so would not only be consistent with other regulations applicable to stationary SI engines, but it would also be more consistent with EPA's applicability analysis, which assumes stationary SI engines will operate for 7,000 hours a year, something emergency engines are prohibited from doing by Federal regulation. Commenters also stated that emergency generators are currently exempt from requirements applicable to non-emergency RICE covered by both

[381] The ERT website is located at *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

the relevant NSPS rule (subpart JJJJ), as well as the relevant NESHAP rule (subpart ZZZZ), and that although the NSPS and NESHAP standards EPA has adopted for emergency RICE do not limit the amount of time they may run for emergency purposes, EPA has recognized in the past that states may assume a maximum of 500 hours of operation to estimate the ''potential to emit'' in issuing air permits for emergency RICE. One commenter asserted that emergency engines operating under other standards currently only operate for emergencies or for a few hours at a time to periodically conduct regular maintenance, that their emissions are low, and that their contribution to the ozone transport issues EPA's proposal seeks to address is negligible. Another commenter stated that the EPA has traditionally exempted emergency engines in past standards because the EPA has typically found that the use of add-on emissions controls cannot be justified due to the cost of the technology relative to the emissions reduction that would be obtained.

Response: With respect to stationary SI emergency engines, the EPA has reviewed the information submitted by the commenters and has decided to exempt such engines from the requirements of the final rule. Exemption of emergency engines is generally consistent with the EPA's treatment of emergency engines in other CAA rulemakings. *See, e.g.,* 40 CFR 63.6585(f). The EPA expects that this change from the proposed rule addresses the concerns expressed by the commenters about the requirements for stationary emergency engines.

The final rule defines emergency engines as engines that are stationary and operated to provide electrical power or mechanical work during an emergency situation. These engines are typically used only a few hours per year, and the costs of emissions control are not warranted when compared to the emissions reductions that would be achieved.

In the final rule, emergency engines are subject to certain compliance requirements on a continuous basis. Continuous compliance requirements include operating limitations that apply during non-emergency use but do not include emissions testing of emergency engines.

Comment: Several commenters raised concerns about the EPA's proposal to establish applicability criteria for engines in Pipeline Transportation of Natural Gas based on design capacity rather than PTE. Other commenters asserted that the horsepower rating of an engine does not necessarily correspond to its annual emissions and that engines with a rated capacity of more than 1,000 hp in this industry sector may operate at low load and/or infrequently and be associated with limited NO_X emissions. One commenter stated that most of the subject facilities in their state that have natural gas fired SI engines with a nameplate capacity rating of 1,000 hp or greater have annual NO_X emissions less than 100 tpy, with nearly 25 percent of them less than 25 tpy. The commenter suggested that the 1,000 hp applicability threshold would result in overcontrol. According to one commenter, the EPA has overestimated the emissions rates and operating hours of engines with a rated capacity of more than 1,000 hp and thus underestimated the size of pipeline RICE that would be expected to emit more than 100 tpy of NO_X annually. According to this commenter, only engines much larger than 1,000 hp are likely to emit at the level EPA deemed appropriate for regulation.

Another commenter suggested that the EPA should use a 150 ton per year threshold that the commenter alleges was used in the Revised CSAPR Update rulemaking so that stationary SI engines are regulated on equal footing with EGUs and raise the 1,000 hp threshold to 2,000 hp, which according to the commenter would not sacrifice the emissions reductions to be achieved.

Response: As explained in the proposal, the EPA found that most RACT requirements and other standards reviewed by the EPA establish applicability criteria for engines based on design capacity rather than PTE. For consistency with preexisting requirements for engines, the EPA selected a design capacity of 1,000 hp for engines to capture the sizes of units identified in Step 3 of our analysis. Based on the Non-EGU Screening Assessment memorandum, engines with a potential to emit of 100 tpy or greater had the most significant potential for NO_X emissions reductions. The EPA recognizes that the use of a 1,000 hp design capacity as part of the applicability criteria may capture low-use units and some units with emissions of less than 100 tons per year. However, it is also not possible to guarantee without an effective emissions control program that all such units could not increase emissions in the future. As discussed in section V of this document, we continue to find that collectively engines with a design capacity of 1,000 hp or higher in the states and industries covered by this final rule emit substantial amounts of NO_X that significantly contribute to downwind air quality problems.

However, in response to concerns raised by commenters while continuing to ensure that this rule establishes an effective emissions control program for these units that is consistent with our Step 3 determinations, the EPA is establishing a compliance alternative using facility-wide emissions averaging, which will allow facilities to prioritize emissions reductions from larger, higher-emitting units. (As previously discussed, we are also establishing an exemption for emergency engines, which also helps ensure that this final rule focuses on larger, more impactful units in this industry.) The facility-wide emissions averaging alternative is explained in the following paragraphs.

Emissions Limitations and Rationale

In developing the emissions limits for the Pipeline Transportation of Natural Gas industry, the EPA reviewed RACT NO_X rules, air permits, and OTC model rules. While some permits and rules express engine emissions limits in parts per million by volume (ppmv), the majority of rules and source-specific requirements express the emissions limits in grams per horsepower per hour (g/hp-hr). The EPA has historically set emissions limits for these types of engines using g/hp-hr and finds that method appropriate for this final FIP as well.

Based on the available information for this industry, including applicable State and local air agency rules and active air permits issued to sources with similar engines, the EPA is finalizing the following emissions limits for stationary SI engines in the covered states. Beginning in the 2026 ozone season and in each ozone season thereafter, the following emissions limits apply, based on a 30-day rolling average emissions rate during the ozone season:

TABLE VI.C–1—SUMMARY OF FINAL NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	Final NO_X emissions limit (g/hp-hr)
Natural Gas Fired Four Stroke Rich Burn	1.0
Natural Gas Fired Four Stroke Lean Burn	1.5
Natural Gas Fired Two Stroke Lean Burn	3.0

The EPA anticipates that, in some cases, affected engines will need to install NO_X controls to comply with the final emissions limits in Table VI.C–1. The emissions limits for four stroke rich burn engines, four stroke lean burn engines and two stroke lean burn engines are designed to be achievable by installing Non-Selective Catalytic Reduction (NSCR) on existing four stroke rich burn engines; installing SCR on existing four stroke lean burn engines; and retrofitting layer combustion on existing two stroke lean burn engines as identified in the Final Non-EGU Sectors TSD. Sources have the flexibility to install any other control technologies that enable the affected units to meet the applicable emissions limit on a continuous basis.

The EPA is establishing provisions that allow any owner or operator of an affected unit in the Pipeline Transportation of Natural Gas Industry to propose a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in this final rule. These provisions will provide some flexibility to owners and operators of affected units to determine which engines to control and at what level, so long as the average emissions across all covered units, on a weighted basis, meet the applicable emissions limits for each engine type. This approach allows facilities to target the most cost-effective emissions reductions and to avoid installing controls on equipment that is infrequently operated.

We provide a more detailed discussion of the basis for the final emissions limits and the anticipated control technologies to be installed in the Final Non-EGU Sectors TSD.

Four Stroke Rich Burn and Four Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit is appropriate for four stroke rich burn engines since even an assumed reduction of 95 percent would result in most engines being able to achieve an emissions rate of 0.5 g/hp-hr. The EPA also requested comment on whether a lower or higher emissions limit is appropriate for four stroke lean burn engines.

Comment: One commenter stated that the limits as proposed were not technically feasible in all circumstances. The commenter explained that its company has 150 four stroke rich burn engines in its fleet and that some of those engines cannot achieve the proposed 1.0 g/hp-hr limit even with both NSCR and layered combustion due to the vintage design of the individual cylinder geometry and the fact that most of these engines are not in production today, which limits availability of parts and retrofit technologies. The commenter asserted that 10 of its four stroke rich burn engines have all available controls on them and half of those still exceed the proposed limits. The commenter estimated that 10 of its four stroke lean burn engines would require SCR to meet the 1.5 g/hp-hr limit and that this control installation would require custom retrofit due to the age of these engines. Furthermore, the commenter stated that if current limits are not achievable in all circumstances, then lower limits are likewise impossible for four stroke rich burn engines and four stroke lean burn engines in even more circumstances. The commenter stated that the technical feasibility of installing controls on any single existing engine varies and depends, in part, on site-specific and engine-specific considerations such as space for the installation of the control, the availability of sufficient power, the emissions reductions required to meet the applicable standards, and the vintage, make, and model of a particular engine. Another commenter recommended tightening the proposed emissions standards for four stroke lean burn engines to an emissions limit similar to Colorado's limit of 1.2 g/hp-hr. A third commenter noted that the District of Columbia Department of Energy and Environment has NO_X emissions limits for both rich- and lean burn engines burning natural gas at 0.7 g/hp-hr.

Response: The EPA is finalizing the emissions limits for both four stroke rich burn engines and four stroke lean burn engines as proposed but also establishing alternative compliance provisions and criteria for establishing case-by-case alternative emissions limits in response to the concerns raised by commenters. NSCR can achieve NO_X reductions of 90 to 99 percent, and engines in California, Colorado, Pennsylvania and Texas have achieved the emissions limits that the EPA had proposed. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 1.0 g/hp-hr emissions limit for four stroke rich burn engines and a 1.5 g/hp-hr emissions limit for four stroke lean burn engines. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

To address the concerns raised by some commenters that not all engines may be able to achieve the emissions limits as proposed due to engine vintage and technical constraints, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. An approved Facility-Wide Averaging Plan would allow the owner or operator of the facility to identify the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs). In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. The provisions governing case-by-case alternative limits are explained in more detail in section VI.C of this document.

Two Stroke Lean Burn Engines

The EPA requested comment on whether a lower emissions limit would be achievable with layered combustion alone for the two stroke lean burn engines covered by this final rule. The

EPA also sought comment on whether these engines could install additional control technology at or below the marginal cost threshold to achieve a lower emissions rate.

Comment: Commenters did not specifically address whether a lower emissions limit would be achievable with layered combustion alone at two stroke lean burn engines. However, one commenter stated that older two stroke lean burn engines generally would not be able to achieve the proposed NO_X emissions limits. The commenter stated that conversion kits are available for several models that can reduce emissions but that such kits are not made for all models, especially older stationary engines. Commenters further stated that where conversion kits are not available, a company would likely have no choice but to replace the older four stroke or two stroke stationary engines, typically at a cost of $2 million to $4 million each.

Two commenters stated that they are required by their state agency to have RACT, BACT, or BART controls, at minimum. Commenters stated that requiring additional controls at facilities already equipped with RACT, BACT or BART control technologies would not achieve the anticipated emissions reductions due to operational factors inherent in the preexisting and pre-controlled equipment and that the achievability of targeted control levels is highly dependent upon a number of variables at each facility.

Another commenter suggested that the EPA set lower limits for two stroke lean burn engines similar to the OTC-recommended limits in the range of 1.5–2.0 g/hp-hr.

Response: Information currently available to the EPA indicates that the amount of emissions reductions achievable with layered combustion controls is unit specific and can range from a 60 to 90 percent reduction in NO_X emissions. The EPA estimates that existing uncontrolled two stroke lean burn engines would need to reduce emissions by up to 80 percent to comply with a 3.0 g/hp-hr emissions limit. The EPA has found that engines in California, Colorado, Pennsylvania and Texas have achieved these emissions rates. Based on this information and the emissions limits and NO_X controls analysis developed by the OTC in a report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012), the EPA is finalizing a 3.0 g/hp-hr emissions limit for two stroke lean burn engines. Although some affected units may be able to achieve a lower emissions rate, we find that a 3.0 g/hp-hr emissions limit generally reflects a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. As explained in the proposed rule and expressed by public commenters, if the EPA were to establish an emissions limit lower than 3.0 g/hp-hr, some two stroke lean burn engines would not be able to meet the emissions limit with the installation of layered combustion control alone. In that case, the lower limit might require the installation of SCR, which the EPA did not find to be cost-effective for two stroke lean burn engines in its Step 3 analysis.[382] The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for this emissions limit.

In response to commenters' concerns about the difficulties involved in retrofitting or replacing older stationary engines to achieve the EPA's proposed emissions limit, the final rule allows any owner or operator of an affected unit to request a Facility-Wide Averaging Plan that would, if approved by EPA, provide an alternative means for compliance with the emissions limits in the final rule. In addition to the Facility-Wide Averaging Plan provisions, the final rule allows owners and operators to seek EPA approval of alternative emissions limits, on a case-by-case basis, where necessary due to technical impossibility or to avoid extreme economic hardship. However, in the context of older or ''vintage,'' high-emitting engines in this industry for which commenters claim emissions control technology retrofit is not feasible, the Agency anticipates taking into consideration the cost associated with alternative compliance strategies, such as replacement with new, far more efficient and less polluting engines, in evaluating claims of extreme economic hardship.

Facility-Wide Averaging Plan

The EPA is finalizing regulatory text that provides for an emissions limit compliance alternative using facility-level emissions averaging. An approved Facility-Wide Averaging Plan will allow the owner or operator of the facility to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control). So long as all of the emissions units covered by the Facility-Wide Averaging Plan collectively emit less than or equal to the total amount of NO_X emissions (in tons per day) that would be emitted if each covered unit individually met the applicable NO_X emissions limitations, the covered units will be in compliance with the final rule. Under this alternative compliance option, facilities have the flexibility to prioritize emissions reductions from larger, dirtier engines.

Comment: Several commenters recommended that the EPA promulgate emissions averaging provisions, as it did in the 2004 NO_X SIP Call Phase 2 rule (69 FR 21604), in which the EPA evaluated and supported reliance on emissions averaging for RICE in the Pipeline Transportation of Natural Gas industry sector. The commenter stated that the EPA's guidance to states on developing an appropriate SIP in response to the SIP Call provided companies the ''flexibility'' to use a number of control options, as long as the collective result achieved the required NO_X reductions, and that many states built their revised SIPs around the emissions averaging approach addressed in this guidance document.[383] One commenter recommended that the EPA allow intra-state emissions averaging across all pipeline RICE owned or operated by the same company. Another commenter asserted that units of certain vintages and units from certain manufacturers will not be able to meet the emissions rate limits the EPA had proposed. The commenter claimed that, absent a system based on source-specific emissions limits, emissions averaging is one of the only practical mechanisms for addressing these challenges.

One commenter stated that it had evaluated the cost of controls for engines in its fleet and that the variety in cost-per-ton for each potential project counsels for a more flexible approach, like an averaging program. Another commenter advocated for an emissions averaging plan that would allow an engine-by-engine showing of economic infeasibility to ensure a cost-effective application of the emissions standards, a reduced impact on natural gas capacity, and a means for addressing the problem presented by achieving

[382] 87 FR 20036, 20143 (noting that an emissions limit below 3.0 g/hp-hr may require some two stroke lean burn engines to install additional controls beyond the EPA's cost threshold).

[383] The commenter refers to an August 22, 2002 memorandum from Lydia N. Wegman, Director, EPA, Air Quality Strategies and Standards Division to EPA Air Division Directors, entitled ''State Implementation Plan (SIP) Call for Reducing Nitrogen Oxides (NO_X)—Stationary Reciprocating Internal Combustion Engines.''

compliance on engines that are technically impossible to retrofit.

One commenter stated that the EPA should also consider allowing companies to choose a mass-based alternative that would ensure emissions reductions align with the tons per year reductions upon which the EPA based its significant contribution and over-control analyses.

Response: Based upon the EPA's 2019 NEI emissions inventory data, the EPA estimates that a total of 3,005 stationary SI engines are subject to the final rule. The EPA recognizes that many low-use engines are captured by the 1,000 hp design capacity applicability threshold. In the process of reviewing public comments, the EPA reviewed emissions averaging plans found in state air quality rules for Colorado, Illinois, Louisiana, New Jersey, and Tennessee.[384] Based on these additional reviews, the EPA is finalizing in § 52.41(c) of this final rule an emissions limit compliance alternative using facility-level emissions averaging. Emissions averaging plans will allow facility owners and operators to determine how to best achieve the necessary emissions reductions by installing controls on the affected engines with the greatest emissions reduction potential rather than on units with lower actual emissions where the installation of controls would be less cost effective. The final rule defines ''facility'' consistent with the definition of this term as it generally applies in the EPA's NSR and title V permitting regulations,[385] with one addition to make clear that, for purposes of this final rule, a ''facility'' may not extend beyond the boundaries of the 20 states covered by the FIP for industrial sources, as identified in § 52.40(b)(2). Because a facility cannot extend beyond this geographic area, a Facility-Wide Averaging Plan also cannot extend beyond the 20-state area covered by the FIP.

To estimate the number of facilities that may take advantage of the Facility-Wide Averaging Plan provisions, and the number of affected units that would install controls under such an emissions averaging plan, the EPA conducted an analysis on a subset of the estimated 3,005 stationary IC engines subject to the final rule. The EPA evaluated the reported actual NO_X emissions data in tpy from a subset of facilities in the covered states using 2019 NEI data for stationary IC engines with design capacities of 1,000 hp or greater. The EPA then identified a number of facilities that have more than one affected engine, calculated each facility's emissions ''cap'' as the total NO_X emissions (in tpy) allowed facility-wide based on the unit-specific NO_X emissions limits applicable to all affected units at the facility, and identified a number of higher-emitting engines at each facility that were candidates for having controls installed. For engines that EPA identified were likely to install controls, the EPA assumed that four stroke rich burn engines, four stroke lean burn engines, and two stroke lean burn engines could achieve a NO_X emissions rate of 0.5 g/hp-hr with the installation of SCR based on data obtained from the Ozone Transport Commission report entitled *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* (October 17, 2012). For the remaining engines identified as uncontrolled, the EPA assumed a NO_X emissions rate of 16 g/hp-hr for all engine types. Thus, under the assumed averaging scenarios, engines with controls installed would achieve emissions levels below the emissions limits in the final rule and would offset the higher emissions from the remaining uncontrolled units.

The EPA then calculated the total facility-wide emissions (in tpy) under various assumed averaging scenarios and compared those totals to each facility's calculated emissions cap (in tpy) to estimate the number of affected units at each facility that would need to install controls to ensure that total facility-wide emissions remained below the emissions cap. Based on these analyses, the EPA found that emissions averaging should allow most facilities to install controls on approximately one-third of the engines at their sites, on average, while complying with the applicable NO_X emissions cap on a facility-wide basis. For a more detailed discussion of the EPA's analysis and related assumptions, see the Final Non-EGU Sectors TSD.

The Facility-Wide Averaging Plan provisions that the EPA is finalizing provide the flexibility needed to address the concerns about the costs of emissions control installations for certain stationary SI engines, by allowing facility owners and operators to average emissions across all participating units and thus to select the most cost-effective means for installing the necessary controls (*i.e.,* by installing controls on the subset of engines that provide the greatest emissions reduction potential at lowest costs and avoiding installation of controls on equipment that is infrequently operated or otherwise less cost-effective to control).

An owner or operator of a facility containing more than one affected unit may elect to use an EPA-approved Facility-Wide Averaging Plan as an alternative means of compliance with the NO_X emissions limits in § 52.41(c). The owner or operator of such a facility must submit a request to the EPA that, among other things, specifies the affected units that will be covered by the plan, provides facility and unit-level identification information, identifies the facility-wide emissions ''cap'' (in tpd) that the facility must comply with on a 30-day rolling average basis, and provides the calculation methodology used to demonstrate compliance with the identified emissions cap. The EPA will approve a request for a Facility-Wide Averaging Plan if the EPA determines that the facility-wide emissions total (in tpd), based on a 30-day rolling emissions average basis during the ozone season, is less than the emissions cap (in tpd) and the plan establishes satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, and recordkeeping requirements.

Compliance Assurance Requirements

The EPA is requiring owners and operators of affected units to conduct annual performance tests in accordance with 40 CFR 60.8 to demonstrate compliance with the NO_X emissions limit in this final rule. The EPA is also requiring owners and operators to monitor and record hours of operation and fuel consumption and to use continuous parametric monitoring systems to demonstrate ongoing compliance with the applicable NO_X emissions limit. For example, owners and operators of engines that utilize layered combustion controls will need to monitor and record temperature, air to fuel ratio, and other parameters as appropriate to ensure that combustion conditions are optimized to reduce NO_X emissions and assure compliance with the emissions limit. For engines using SCR or NSCR, owners and operators must monitor and record parameters such as inlet temperature to the catalyst

[384] *See* Code of Colorado Regulations, Regulation Number 7 (5 CCR 1001–9), Part E, Section I.D.5.c., Illinois Administrative Code, Title 35, Section 217.390, Louisiana Administrative Code, Title 33, Section 2201, New Jersey Administrative Code, Title 7, Chapter 27, Section 19.6, and Rules of the Tennessee Dept. of Environment and Conservation, Rule 1200–03–27–.09.

[385] See 40 CFR 51.165(a)(1)(ii)(A), 51.166(b)(6)(i), and 52.21(b)(6)(i) (defining ''building, structure, facility, or installation'' for Nonattainment New Source Review and Prevention of Significant Deterioration permits) and *Natural Resources Defense Council* v. *EPA,* 725 F.2d 761 (D.C. Cir. 1984) (vacating and remanding EPA's categorial exclusion of vessel activities from this definition); see also 40 CFR 70.2 (defining ''major source'' for title V operating permits).

and pressure drop across the catalyst. For affected engines that meet the certification requirements of § 60.4243(a), however, the facility-wide emissions calculations may be based on certified engine emissions standards data pursuant to § 60.4243(a), instead of performance tests.

In calculating the facility-wide emissions total during the ozone season, affected engines covered by the Facility-Wide Averaging Plan must be identified by each engine's nameplate capacity in horsepower, its actual operating hours during the ozone season, and its emissions rates in g/hp-hr from certified engine data or from the most recent performance test results for non-certified engines according to § 52.41(e).

Comment: Several commenters stated that semi-annual performance testing would not be appropriate due to its high costs and limited benefits. One commenter proposed a ''step-down'' testing alternative that could be conducted after establishing an engine's initial compliance via performance testing. Under this approach, owners and operators would conduct one performance test and would only need to conduct a second performance test within a given year if the first performance test demonstrated that an engine was not meeting the applicable emissions standards.

Another commenter asserted that to test all of its 950 units, a minimum of 12 months would be needed rather than the six months the EPA had proposed to provide (or five months if the EPA would require one of the semi-annual tests to be conducted during the ozone season). The commenter stated that the EPA had accounted for these operational realities in the past and that under the NSPS and NESHAP, testing is generally required only once for every 8,760 hours of run time. The commenter asserted that there is no reason to require more frequent testing than those required under the NSPS and NESHAP.

Several commenters requested that the EPA allow for reduction in the frequency of testing to once every two years if testing shows that NO_X emissions are no more than 75 percent of permitted NO_X emissions limits. In addition, several commenters stated that since the rule is intended to address the ozone season, a single, annual test is more feasible than semi-annual testing and reporting.

Response: For the stationary SI engines subject to this final rule, the EPA is revising the frequency of required performance tests from a semi-annual basis to once per calendar year. As commenters correctly pointed out, the emissions limits in these final FIPs only apply during the 5-month ozone season and testing once per calendar year should be sufficient to confirm the accuracy of the parameters being monitored to determine continuous compliance during the ozone season. The EPA also agrees with commenters that the annual tests required under the final rule need not occur during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: Commenters generally stated that requiring CEMS would add an unnecessary cost and complexity, would provide no emissions reduction benefit for the affected units the proposed FIP intends to control and are not warranted due to the availability of other established methods of compliance assurance, such as parametric monitoring and periodic testing. One commenter stated that requiring CEMS would add unnecessary CEMS testing obligations. Another commenter stated that the costs associated with CEMS and frequent performance testing on affected RICE would be as much, if not more, than the costs associated with installation and operation of some of the control technologies EPA has considered in setting the proposed emissions limits. According to one commenter, the EPA has traditionally agreed with this viewpoint on the high cost of CEMS, as most stationary engines are not currently required under the NSPS or NESHAP to install or operate CEMS.

Another commenter stated that in addition to cost, there are other barriers to installing CEMS on RICE across the Pipeline Transportation of Natural Gas industry. Many RICE in the Pipeline Transportation of Natural Gas industry are located at remote, unstaffed locations, meaning that there would be no staff available to respond and react to communication or alarms from CEMS.

Response: The EPA acknowledges the costs associated with the installation and maintenance of CEMS at affected units in the Pipeline Transportation of Natural Gas industry and agrees that it is not necessary to require CEMS for purposes of compliance with the requirements of this final rule for this industry. Accordingly, the EPA is not finalizing requirements for affected units in this industry sector to install or operate CEMS. Instead, the EPA is requiring parametric monitoring protocols, as described earlier, coupled with an annual performance test, which will ensure that the emissions limits are legally and practically enforceable on a continuous basis, and that data are recorded, reported, and can be made publicly available, ensuring the ability of state and Federal regulators and other persons under CAA sections 113 and 304 to enforce the requirements of the Act.

2. Cement and Concrete Product Manufacturing

Applicability

For cement kilns in the Cement and Cement Product Manufacturing industry, the EPA is finalizing the proposed applicability provisions without change. The affected units in this industry are cement kilns that emit or have a PTE of 100 tpy or more of NO_X. The EPA received comments regarding the definition of PTE, which we address in section VI.C, but no comments concerning the 100 tpy PTE threshold for applicability purposes.

Emissions Limitations and Rationale

As explained in the proposal, the EPA based the proposed emissions limits for cement kilns on the types of limits being met across the nation in RACT NO_X rules, NSPS, air permits, and consent decrees. Based on these requirements, the EPA proposed emissions limits in the form of mass of pollutant emitted (in pounds) per kiln's clinker output (in tons), *i.e.,* pounds of NO_X emitted per ton of clinker produced during a 30-operating day rolling average period. Further, the EPA proposed specific emissions limits for long wet, long dry, preheater, precalciner, and combined preheater/precalciner kilns. The EPA also proposed a daily source cap limit that would apply to all units at a facility. Based on information received from public comments, the EPA is removing the daily source cap limit but finalizing the emissions limits as proposed in all other respects, as shown in Table VI.C–2.

TABLE VI.C–2—SUMMARY OF NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

Comment: Numerous commenters raised concerns about designing a source cap limit based on average annual production in tons of clinker and kiln type. Commenters stated that the source cap limit equation as used in a prior action applied to long wet and dry preheater-precalciner or precalciner kilns and did not include other kiln types. Commenters expressed concern that the CAP2015 Ozone Transport equation the EPA proposed in this rule could lead to artificially low and restrictive daily emissions caps for facilities that experienced a temporary decrease in production due to the COVID–19 pandemic, during the historical three-year period proposed for use in determining the NO_X source cap. Also, commenters expressed concern that the proposed daily emissions cap limit originated as a local or regional limit for a single county and would not be appropriate for national application without further evaluation taking into account the specific characteristics of cement kilns in other states. One commenter suggested more stringent emissions limits than those the EPA had proposed for individual kiln types.

Response: The EPA is not finalizing the proposed daily source cap limit as the Agency agrees with the commenters that this proposed limit would be unnecessarily restrictive and was based on a formula that did not include all kiln types. Given the unusual reduction in cement production activities due to the COVID–19 pandemic, production rates during the 2019–2021 period are not representative of cement plants activities generally. Accordingly, use of the proposed daily source cap limit would result in an artificially restrictive NO_X emissions limit for affected cement kilns, particularly when this sector operates longer hours during the spring and summer construction season. With respect to those comments supporting more stringent emissions limits than those the EPA proposed for individual kiln types, we disagree given the significant differences among different kilns in design, configuration, age, fuel capabilities, and raw material composition. The EPA finds that the ozone season emissions limits for individual kiln types listed in Table VI.C–2 will achieve the necessary emissions reductions for purposes of eliminating significant contribution as defined in section V and is, therefore, finalizing these emissions limitations without change.

Comment: One commenter supported retirement of existing long wet kilns and replacement of these kilns with modern kilns. Other commenters opposed the phase out and retiring of these kilns, stating that many of the screened kilns have SNCR already installed and questioning whether replacement of existing long wet kilns is cost-effective. Some commenters also stated that according to EPA's ''NO_X Control Technologies for the Cement Industry, Final Report,'' SNCR is not an appropriate NO_X control technique for long wet kilns.

Response: The EPA appreciates the challenges identified by commenters, such as site-specific technical evaluation and review and significant capital investment associated with undertaking kiln conversions or to install new kilns and is not finalizing any requirements to replace existing long wet kilns in this rule.

Comment: Several commenters expressed concern about the supply chain issues relevant to the procurement, design, construction, and installation of control devices, as well as securing related contracts, for the cement industry, particularly when cement sources will be competing with the EGU and other industrial sectors for similar services. One commenter stated that many preheater/precalciner kilns are already equipped with SNCR and that one facility not equipped with SNCR is already meeting NO_X emissions levels of 1.95 lb/ton of clinker or less. The commenter stated that the EPA should revise its assessment of potential NO_X reductions and cost estimates by accurately accounting for existing operating efficiencies and control devices at cement kilns.

Response: The EPA's response to comments on the time needed for installation of controls for non-EGU sources is provided in section VI.A. Regarding the comment that certain facilities may already have SNCR control technology installed, we recognize that many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

Compliance Assurance Requirements

The EPA received no comments on the proposed test methods and procedures provisions for the cement industry. Therefore, we are finalizing the proposed test methods and procedures for affected cement kilns without change.

Comment: Commenters generally supported requiring performance testing or installation of CEMS on affected cement kilns. Some commenters suggested that no performance testing should be required and others suggested that performance testing should only be required when a title V permit is due for renewal (every 5 years). One commenter suggested requiring sources to conduct stack tests during the ozone season.

Response: Affected kilns that operate a NO_X CEMS may use CEMS data consistent with the requirements of 40 CFR 60.13 in lieu of performance tests to demonstrate compliance with the requirements of this final rule. For affected kilns subject to this final rule that do not employ NO_X CEMS, the EPA is adjusting the performance testing frequency and requiring kilns to conduct a performance test on an annual basis during a given calendar year.[386] The EPA finds that annual performance testing and recordkeeping of cement production and fuel consumption during the ozone season will assure compliance with the emissions limits during the ozone season (May through September) each year for purposes of this rule. The required annual performance test may be performed at any time during the calendar year. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

Comment: One commenter stated that CEMS has been used successfully at its facility. Another commenter explained that the inside of a cement kiln is an extremely challenging environment for making any kind of continuous measurement as temperatures are high, and there is a lot of dust and tumbling clinker can damage in situ measuring instruments.

Response: The majority of cement kilns in the United States are already equipped with CEMS. However, in response to commenters concerns regarding the installation of CEMS, the EPA is finalizing alternative compliance requirements in lieu of CEMS. Owners or operators of affected emissions units without CEMS installed must conduct annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. Specifically, owners or operators of affected units without CEMS must monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits.

3. Iron and Steel Mills and Ferroalloy Manufacturing

Applicability

The EPA is establishing emissions control requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to reheat furnaces that directly emit or have the potential to emit 100 tpy or more of NO_X. After review of all available information received during public comment, the EPA has determined that there is sufficient information to determine that low-NO_X burners can be installed on reheat furnaces. As explained further in the Final Non-EGU Sectors TSD, the EPA identified 32 reheat furnaces with low-NO_X burners installed and has concluded that low-NO_X burners are a readily available and widely implemented emissions reduction strategy.[387] This rule defines reheat furnaces to include all furnaces used to heat steel product—metal ingots, billets, slabs, beams, blooms and other similar products—to temperatures at which it will be suitable for deformation and further processing.

Comment: Several industry commenters requested that the EPA not include certain iron and steel emissions units—including blast furnaces, basic oxygen furnaces (BOFs), ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, and electric arc furnaces (EAFs)—in the final rule as proposed due to, among other things, the uniqueness of each emissions unit, various design-related challenges, and expected impossibility of successful implementation of add-on NO_X control technology. Commenters expressed concern about requirements to install SCR for all iron and steel units for which the EPA proposed emissions limits. The commenters stated that iron and steel units had not installed SCR except in a few rare instances for experimental reasons and that SCR technology was not readily available or known for the iron and steel industry, unlike the control technologies expected to be installed in other non-EGU industries. Furthermore, commenters stated that SCR had not been applied for RACT, BACT, or LAER purposes on iron and steel units.

Response: In light of the comments we received on the complex economic and, in some cases, technical challenges associated with implementation of NO_X control technologies on certain emissions units in this sector, the EPA is not finalizing the proposed emissions limits for blast furnaces, BOFs, ladle and tundish preheaters, annealing furnaces, vacuum degassers, taconite kilns, coke ovens, or EAFs.

The EPA is aware of many examples of low-NO_X technology utilized at furnaces, kilns, and other emissions units in other sectors with similar stoichiometry, including taconite kilns, blast furnace stoves, electric arc furnaces (oxy-fuel burners), and many other examples at refineries and other large industrial facilities. The EPA anticipates that with adequate time, modeling, and optimization efforts, such NO_X reduction technology may be achievable and cost-effective for these emissions units in the Iron and Steel Mills and Ferroalloy Manufacturing sector as well. However, the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NO_X controls, including SCR or other NO_X control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry. We provide a more detailed discussion of the economic and technical issues associated with implementation of NO_X control technologies on these emissions units, including information provided by commenters, in section 4 of the Final Non-EGU Sectors TSD.

Reheat furnaces are the only type of emissions unit within the Iron and Steel Mills and Ferroalloy Manufacturing industry that this final rule applies to. Low-NO_X controls (*e.g.,* low-NO_X burners) are a demonstrated control technology that many reheat furnaces have successfully employed.

Comment: One commenter claimed that the proposed definition of ''reheat furnaces'' is overly vague and requested that the EPA amend the definition. Specifically, the commenter asserted that the EPA's proposed definition does not indicate what counts as ''steel product'' and whether this includes only products that have already been manufactured into some form before being introduced to a reheat furnace, or whether it also includes steel that has never left the original production process, such as hot steel coming directly from a connected casting process which has not yet been formed into a definitive product. The commenter referenced the definition of reheat furnaces in Ohio's RACT regulations as an example to consider.

Response: In response to these comments, the EPA is finalizing a definition of reheat furnaces that is consistent with the definition in Ohio's NO_X RACT regulations. *See* Ohio Admin. Code 3745–110–01(b)(35) (March 25, 2022). Specifically, the EPA is defining reheat furnaces to mean ''all furnaces used to heat steel product, including metal ingots, billets, slabs, beams, blooms and other similar products, to temperatures at which it will be suitable for deformation and further processing.''

[386] 40 CFR 63.11237 ''Calendar year'' defined as the period between January 1 and December 31, inclusive, for a given year.

[387] See Final Non-EGU Sectors TSD, Section 4.

Emissions Control Requirements, Testing, and Rationale

Based on the available information for this industry, applicable Federal and state rules, and active air permits or enforceable orders issued to affected facilities in the iron and steel and ferroalloy manufacturing industry, the EPA is finalizing requirements for each facility with an affected reheat furnace to design, fabricate and install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by at least 40 percent by volume, and to conduct performance testing before and after burner installation to set emissions limits and verify emissions reductions from pre-installation emissions rates. Each low-NO_X burner shall be designed to achieve at least 40 percent NO_X reduction from existing reheat furnace exhaust emissions rates. Each facility with an affected reheat furnace shall, within 60 days of conclusion of the post-installation performance test, submit testing results to the EPA to establish NO_X emissions limits over a 30-day rolling average. Each proposed emissions limit must be supported by performance test data and analysis.

In evaluating potential emissions limits for the Iron and Steel and Ferroalloy Manufacturing industry, the EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees. These rules and source-specific requirements most commonly express emissions limits for this industry in terms of mass of pollutant emitted (pounds) per operating hour (hour) (*i.e.,* pounds of NO_X emitted per production hour), pounds per energy unit (*i.e.,* million British thermal unit (mmBtu)), or pounds of NO_X per ton of steel produced. Regulated iron and steel facilities, including facilities operating reheat furnaces in this sector, routinely monitor and keep track of production in terms of tons of steel produced per hour (heat rate) as it pertains to each facility's rate of iron and steel production. Several facilities, including Steel Dynamics, Columbia, Indiana, Cleveland-Cliffs, Cleveland, Ohio, and Cleveland-Cliffs, Burns Harbor, Indiana, are already operating various types of reheat furnaces with low-NO_X burners and achieving emissions rates as low as 0.11 lb/mmBtu of NO_X. The EPA identified at least nine reheat furnaces with a PTE greater than 100 tpy, including slab, rotary hearth, and walking beam furnaces, that have installed low-NO_X burners and are achieving various emissions rates.[388]

Due to variations in the emissions rates that different types of reheat furnaces can achieve, the EPA is not finalizing one emissions limit for all reheat furnaces and is instead requiring the installation of low-NO_X burners or equivalent low-NO_X technology designed to achieve a minimum 40 percent reduction from baseline NO_X emission levels, together with source specific emissions limits to be set thereafter based on performance testing. Specifically, the final rule requires that each owner or operator of an affected unit submit to the EPA, within one year after the effective date of the final rule, a work plan that identifies the low-NO_X burner or alternative low-NO_X technology selected, the phased construction timeframe by which the owner or operator will design, install, and consistently operate the control device, an emissions limit reflecting the required 40 percent reduction in NO_X emission levels, and, where applicable, performance test results obtained no more than five years before the effective date of the final rule to be used as baseline emissions testing data providing the basis for the required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing to establish baseline emissions data.

Comment: One commenter stated that the standard practice for setting NO_X limits for iron and steel sources often requires consideration of site or unit-specific issues. Similarly, another commenter stated that a single limit would not provide an adequate basis for establishing NO_X emissions limits that will universally apply to multiple, unique facilities. The same commenter stated that NO_X reduction in certain furnaces is routinely achievable by combustion controls or measures other than SCR.

Response: The EPA acknowledges the difficulty in crafting one emissions limit for multiple iron and steel facilities and units of varying size, age, and design, in light of the unique issues associated with varying unit types in this particular industry. We also acknowledge that in some cases, reheat furnaces are equipped with recently installed, high-efficiency low-NO_X burners. Many sources throughout the EGU sector and non-EGU industries covered by this rule may already be achieving enforceable emissions performance commensurate with the requirements of this action. This is entirely consistent with the logic of our 4-step interstate transport framework, which is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NO_X emissions performance during the ozone season. *See EME Homer City,* 572 U.S. at 519. Sources that are already achieving that level of performance will face relatively limited compliance costs associated with this rule.

The EPA is finalizing requirements for reheat furnaces to install high-efficiency low-NO_X burners designed to reduce NO_X emissions from pre-installation emissions rates by 40 percent by volume, and to perform pre- and post-installation performance testing at exhaust outlets to determine rate-based emissions limits for reheat furnaces in lb/hour, lb/mmBtu, or lb/ton on a rolling 30-operating day average. Owners and operators of affected units must also monitor NO_X emissions from reheat furnaces using CEMS or annual performance testing and recordkeeping and operate low-NO_X burners in accordance with work practice standards set forth in the regulatory text. Due to the many types of emissions units within the Iron and Steel Mills and Ferroalloy Manufacturing industry, and the limited information available at this time regarding NO_X control options that are achievable for these units, the EPA is finalizing requirements only for reheat furnaces at this time.

Comment: Commenters expressed concern that the proposed emissions limits identified both a 3-hour and a 30-day averaging time for the same limits and requested that the EPA clarify the averaging time in the final rule. Commenters requested that the EPA finalize limits with a 30-day averaging time consistent with the requirements for other non-EGU industries.

Response: In determining the appropriateness of 30-day rolling averaging times, the EPA initially reviewed the NESHAP for Iron and Steel Foundries codified at 40 CFR part 63, subpart EEEEE, the NESHAP for Integrated Iron and Steel manufacturing facilities codified at 40 CFR part 63, subpart FFFFF, the NESHAP for Ferroalloys Production: Ferromanganese and Silicomanganese codified at 40 CFR part 63, subpart XXX, and the NESHAP for Ferroalloys Production Facilities codified at 40 CFR part 63, subpart YYYYYY. The EPA also reviewed

[388] Specifically, through a review of title V permits, the EPA identified reheat furnaces with low-NO_X burners installed at Steel Dynamics in Columbia City, Indiana (two furnaces), Steel Dynamics in Butler, Indiana (one furnace), Cleveland Cliffs in Burns Harbor, Indiana (four furnaces), Cleveland Cliffs in East Chicago, Indiana (one furnace), and Cleveland Cliffs in Cleveland, Ohio (one furnace). For a further discussion of the limits and information on these facilities, see the Final Non-EGU Sectors TSD.

various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations. Based on this information and the information provided by public commenters, the EPA is requiring a 30-operating day rolling average period as the averaging timeframe for reheat furnaces. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while providing the flexibility needed to address fluctuations in operations and production.

Compliance Assurance Requirements

The EPA is finalizing requirements for each owner or operator of an affected unit in the Iron and Steel Mills and Ferroalloy Manufacturing industry to use CEMS or annual performance tests and continuous parametric monitoring to determine compliance with the 30-day rolling average emissions limit during the ozone season. Facilities choosing to use CEMS must perform an initial RATA per CEMS and maintain and operate the CEMS according to the applicable performance specifications in 40 CFR part 60, appendix B. Facilities choosing to use testing and continuous parametric monitoring for compliance purposes must use the test methods and procedures in 40 CFR part 60, appendix A–4, Method 7E, or other EPA-approved (federally enforceable) test methods and procedures.

Comment: Several commenters raised concerns with the requirement to install and operate CEMS to monitor NO_X emissions. Commenters cited the high relative costs of installing CEMS, especially for smaller units with lower actual emissions, and the complexities with installing CEMS on mobile reheat furnaces. Further, commenters explained that due to the unique configuration of certain facilities, it would be impossible for a CEMS to differentiate emissions from a reheat furnace and other units, like waste heat boilers. As an alternative to CEMS, commenters requested that the EPA finalize similar monitoring and recordkeeping requirements as proposed for the Cement and Concrete Product Manufacturing industry in the proposed rule, which allow for CEMS or performance testing and recordkeeping. Commenters explained that for reheat furnaces that are natural gas-fired, emissions can be tracked by relying on vendor guarantees and emissions factors and natural gas throughput.

Response: The EPA reviewed comments received from the industry regarding their concerns of affected units within the iron and steel mills and ferroalloy manufacturing sector being required to demonstrate compliance through CEMS. The EPA acknowledges the cost associated with the installation and maintenance of CEMS to demonstrate compliance with the finalized emissions standards for reheat furnaces. In this final rule, the EPA is revising the compliance assurance requirements to provide flexibility to owners or operators of affected units. Compliance may be demonstrated through CEMS or annual performance testing and continuous parametric monitoring to demonstrate compliance with the emissions limits in this final rule. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. For sources relying on annual performance tests and continuous parametric monitoring to assure compliance, the EPA is requiring that sources keep records of production and fuel usage during the ozone season to assure compliance with the emissions limits on a 30-day rolling average basis. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season. However, where sources are able to do so, we recommend conducting a stack test in the period relatively soon before the start of the ozone season. This would provide the greatest assurance that the emissions control systems are working as intended and the applicable emissions limit will be met when the ozone season starts.

4. Glass and Glass Product Manufacturing

Applicability

The EPA is finalizing regulatory requirements for the Glass and Glass Product Manufacturing source category that apply to furnaces that directly emit or have a PTE of 100 tpy or more of NO_X. For this industry, the EPA is finalizing the proposed applicability provisions without change.

Comment: One commenter requested that the applicability threshold for glass manufacturing furnaces should be based on a unit's design production capacity instead of the proposed applicability criteria (*i.e.,* units that directly emit or have the potential to emit 100 TPY or more of NO_X). The commenter stated that the production capacity for glass manufacturing furnaces is a more relevant basis for applicability and would focus the EPA analysis on cost-effective regulations.

Response: During the EPA's development of the proposed emissions limits, the EPA reviewed the applicability provisions in various state RACT NO_X rules, air permits, consent decrees, and Federal regulations applicable to glass manufacturing furnaces. Most of these applicability provisions were expressed in terms of actual emissions or PTE. Given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA finds that applicability criteria based on emissions or potential to emit are the most appropriate way to capture higher-emitting glass manufacturing furnaces that contribute NO_X emissions to downwind receptors.

Emissions Limitations and Rationale

The EPA is finalizing the proposed NO_X emissions limits for furnaces within the Glass and Glass Product Manufacturing industry, except that for flat glass manufacturing furnaces the EPA is finalizing an emissions limit slightly lower than the limit we had proposed, based on a correction to a factual error in our proposal. For further discussion of the basis for the form and level of the final emissions limits, see the proposed rule, 87 FR 20036, 20146 (April 6, 2022) (discussing EPA review of state RACT rules, NSPS, and other regulations applicable to the Glass and Glass Product Manufacturing industry). Several comments supported the EPA's effort to regulate sources within the Glass and Glass Product Manufacturing industry but also requested that the EPA establish more stringent emissions limits for this industry.

Comment: One commenter stated that NO_X emissions from the Glass and Glass Product Manufacturing industry are not currently subject to any Federal NSPS and that the industry is expected to grow in the coming years. The commenter stated that while the EPA's proposed limits on glass furnaces fell within the ranges of limits required by various states and air districts, they fell at the weakest levels within those ranges. For example, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for container glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1 to 4 lb/ton. Similarly, the commenter stated that the EPA had proposed a 4.0 lb/ton NO_X emissions limit for pressed/blown glass manufacturing furnaces, while state and local NO_X emissions limits for these emissions units range from 1.36 to 4 lb/ton, and that EPA had proposed a 9.2 lb/ton NO_X emissions limit for flat glass manufacturing furnaces, while state NO_X emissions limits for these emissions units range from 5–9.2 lb/ton. The commenter urged the EPA to establish emissions limits lower than those the EPA had proposed.

Response: The EPA is finalizing the emissions limits for affected units in the glass and glass product manufacturing industry as proposed for all but flat glass manufacturing furnaces, for which the EPA is finalizing a slightly lower emissions limit to reflect a correction to a factual error in our proposal. During the EPA's development of the proposed emissions limits, the EPA reviewed the control requirements or recommendations and related analyses in various RACT NO_X rules, air permits, Alternative Control Techniques (ACT) documents, and consent decrees to determine the appropriate NO_X emissions limits for the different types of glass manufacturing furnaces. Based on these reviews and given the significant differences in the types, designs, configurations, ages, and fuel capabilities among glass furnaces, and differences in raw material compositions within the sector, the EPA has concluded that it is appropriate to finalize the emissions limits for this industry as proposed, except for the limit proposed for flat glass manufacturing furnaces. For flat glass manufacturing furnaces, the EPA had proposed a NO_X emissions limit of 9.2 pounds (lbs) per ton of glass pulled but is finalizing a limit of 7.0 lbs/ton of glass pulled on a 30-day rolling average basis. This is based on our review of specific state RACT NO_X regulations that contain a 9.2 lbs/ton limit averaged over a single day but contain a 7.0 lbs/ton limit over a 30-day averaging period. This change aligns the final limit for flat glass manufacturing furnaces with the correct averaging time and is consistent with both the state RACT regulations that we reviewed [389] and our evaluation of cost-effective controls for this industry in the supporting documents for the proposed and final rule.

The EPA acknowledges that NO_X emissions from some glass manufacturing furnaces are subject to control under other regulatory programs, such as those adopted by states to meet CAA RACT requirements, and that some of these programs have implemented more stringent emissions limits than those the EPA is finalizing in these FIPs. However, as noted in the preamble to the proposed rule and related TSD, many OTR states do not establish specific NO_X emissions limits for glass manufacturing sources.[390] *See* 87 FR 20146. In addition to state RACT rules, air permits, ACT documents, and consent decrees applicable to this industry, the EPA reviewed reports and recommendations from the National Association of Clean Air Agencies (NACAA), the European Union Commission, and EPA's Menu of Control Measures (MCM) to identify potentially available control measures for reducing NO_X emissions from the glass manufacturing industry. The EPA also reviewed permit data for existing glass manufacturing furnaces to identify control devices currently in use at these sources. Based on these reviews, we find that the final emissions limits for the Glass and Glass Product Manufacturing industry provided in Table VI.C.3–1 generally reflect a level of control that is cost-effective for the majority of the affected units and sufficient to achieve the necessary emissions reductions. The Final Non-EGU Sectors TSD provides a more detailed explanation of the basis for these emissions limits.

TABLE VI.C.3–1—SUMMARY OF FINALIZED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	NO_X emissions limit (lbs/ton of glass produced, 30 operating-day rolling average)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	7.0

Alternative Emissions Standards During Periods of Start-Up, Shutdown, and Idling

Comment: Numerous commenters urged the EPA to provide additional flexibilities, alternative NO_X emissions limits, or exceptions to the NO_X emissions limits for glass manufacturing furnaces during periods of startup, shutdown and idling. Commenters requested that the EPA consider excluding days with low glass pull (*e.g.,* abnormally low production rate), furnace start-up days, furnace maintenance days, and malfunction days from the definition of ''operating day'' to allow for exclusion of these days from the calculation of an emissions unit's 30-operating day rolling average emissions. The commenters argued that because the glass furnace temperature is much lower during these periods than they are during normal operating conditions, it would be technologically infeasible to equip furnaces with NO_X control devices including SCR. Commenters also stated that because control equipment cannot be operated during these periods without damaging the equipment, it would be very difficult or impossible to meet the proposed NO_X limits during these periods.

Response: After review of the comments received and the EPA's assessment of current practices within

[389] For example, Pennsylvania's RACT NO_X emission limits for flat glass furnaces are 7.0 lbs of NO_X per ton of glass produced on 30-day rolling average. *See* Title 25, Part I, Subpart C, Article III, Section 129.304, available at *https://casetext.com/regulation/pennsylvania-code-rules-and-regulations/title-25-environmental-protection/part-i-department-of-environmental-protection/subpart-c-protection-of-natural-resources/article-iii-air-resources/chapter-129-standards-for-sources/control-of-nox-emissions-from-glass-melting-furnaces/section-129304-emission-requirements.*

[390] See Proposed Non-EGU Sectors TSD at 56, EPA–HQ–OAR–2021–0668–0145.

the glass manufacturing industry, the EPA is establishing provisions for alternative work practice standards and emissions limits that may apply in lieu of the emissions limits in § 52.44(c) during periods of start-up, shutdown, and idling. The emissions limits for glass melting furnaces in § 52.44(c) do not apply during periods of start-up, shutdown, and/or idling at affected units that comply instead with the alternative requirements for start-up, shutdown, and/or idling periods specified in § 52.44(d), (e), and/or (f), respectively. The EPA has modeled these alternative requirements that apply during startup, shutdown, and idling to some extent on State RACT requirements identified by commenters.[391] These alternative work practice standards adequately address the seven criteria that the EPA has recommended states consider when establishing appropriate alternative emissions limitations for periods of startup and shutdown.[392] We provide a more detailed evaluation of these provisions in the TSD supporting this final rule.

Specifically, each owner or operator of an affected unit seeking to comply with alternative work practice standards in lieu of emissions limits during startup or shutdown periods must submit specific information to the Administrator no later than 30 days prior to the anticipated date of startup or shutdown. The required information is necessary to ensure that the furnace will be properly operated during the startup or shutdown period, as applicable. The final rule establishes limits on the number of days when the owner or operator may comply with alternative work practice standards in lieu of emissions limits during startup and shutdown, depending on the type of glass furnace. Additionally, the owner or operator must maintain operating records and additional documentation as necessary to demonstrate compliance with the alternative requirements during startup or shutdown periods. For startups, the owner or operator must place the emissions control system in operation as soon as technologically feasible to minimize emissions. For shutdowns, the owner or operator must operate the emissions control system whenever technologically feasible to minimize emissions.

For periods of idling, the owner or operator of an affected unit may comply with an alternative emissions limit calculated in accordance with a specific equation to limit emissions to an amount (in pounds per day) that reflects the furnace's permitted production capacity in tons of glass produced per day. Additionally, the owner or operator must maintain operating records as necessary to demonstrate compliance with the alternative emissions limitations during idling periods. During idling, the owner or operator must operate the emissions control system to minimize emissions whenever technologically feasible.

All-Electric Glass Furnaces

The EPA solicited comment on whether it is feasible or appropriate to phase out and retire existing glass manufacturing furnaces in the affected states and replace them with more energy efficient and less emitting units like all-electric melter installations. The EPA also requested comment on the time needed to complete such a task. All-electric melters are glass melting furnaces in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass.[393] The EPA received numerous comments from the glass industry regarding their concerns with replacing an existing glass manufacturing furnace with an all-electric melter. The commenters stated that various operational restrictions present within all-electric furnaces prevent these units from being implemented throughout the industry, including limited glass production output, reduced glass furnace life, and increased glass plant operating cost due to high levels of electric current usage. Based on the EPA's review of comments submitted on this issue, the EPA has decided not to establish any requirements to replace existing glass manufacturing furnaces with all-electric furnaces at this time. We provide in the following paragraphs a summary of the comments and the EPA's responses thereto.

Comment: One commenter stated that the lifetime of an all-electric glass melting furnace is only about three to five years before it must be rebricked, compared to well-maintained natural gas or hybrid furnace that may be operated continuously for as long as fifteen to twenty years between rebricking events. The commenter also states that electric furnaces for manufacture of glass containers are limited to a maximum glass production of about 120 tons per day, which is a stark contrast to large natural gas fired glass melting furnaces, which are capable of producing over 400 tons of glass per day. The commenter also stated that the cullet percentage is greatly reduced in all-electric furnaces which increases energy consumption in the affected facility.

Response: At proposal, the EPA solicited comment on whether it is feasible or appropriate for owners or operators of existing glass manufacturing furnaces to phase out and retire their units and replace them with less emitting units like all-electric furnace installations. As explained in the Final Non-EGU Sectors TSD, over the last few decades the demand for flat, container, and pressed/blown glass has continued to grow annually. Nitrogen oxides remain one of the primary air pollutants emitted during the production and manufacturing of glass products. However, no current Federal CAA regulation controls NO_X emissions from the industry on a category-wide basis.[394] Therefore, the glass manufacturing industry has conducted various pollution prevention and research efforts to help identify preferred techniques for the control of NO_X. Some of these studies revealed recent trends to control NO_X emissions in the glass industry, including the use of all-electric glass furnaces. We understand based on the comments received from the glass manufacturing industry that significant differences exist in the design, configuration, age, and replacement cost of glass furnaces and in the feasibility of controls and raw material compositions. These differences as well as the production limitations present with all-electric furnaces create difficulties in implementing all-electric furnaces across the industry while keeping up with glass product demands. Therefore, the EPA is not mandating any requirement for owners or operators of existing glass manufacturing furnaces to replace their units with all-electric furnaces.

Combustion Modification and Post-Combustion Modification Control Devices

According to the EPA's ''Alternative Control Techniques Document—NO_X Emissions from Glass

[391] See Pennsylvania Code, Title 25, Part I, Subpart C, Article III, Sections 129.305–129.307 (effective June 19, 2010), available at *https://www.pacodeandbulletin.gov/Display/pacode?file=/secure/pacode/data/025/chapter129/chap129toc.html&d=reduce* and San Joaquin Valley Unified Air Pollution Control District, Rule 4354, ''Glass Melting Furnaces,'' sections 5.5–5.7 (amended May 19, 2011), available at *https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf*.

[392] See 80 FR 33840, 33914 (June 12, 2015) (identifying the EPA's recommended criteria for developing and evaluating alternative emissions limitations applicable during startup and shutdown).

[393] *See* definitions in 40 CFR part 60, subpart CC.

[394] See Final Non-EGU Sectors TSD.

Manufacturing,'' [395] glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO_X burners and oxy-firing. At proposal, the EPA solicited comments on whether it is feasible or appropriate to require sources with existing glass manufacturing furnaces in affected states that currently utilize these combustion modifications to add or operate a post-combustion modifications control device like SNCR or SCR to further improve their NO_X removal efficiency. The EPA received numerous comments from the glass industry that detailed the differences present in glass furnace designs, operations and finished product that influenced the type of combustion modification or post-combustion modification control device that is feasible for such unit. Several commenters have requested that the EPA focus on establishing an emissions limit rather than specifying the use of a particular control technology given the significant differences across glass furnaces. As a result of the comments received, the EPA is not specifically requiring affected units to install combustion modification and post-combustion controls to meet the finalized emissions limits. The EPA is finalizing the emissions limits as proposed, which may be met with combustion modifications (*e.g.,* low-NO_X burners, oxy-firing), process modifications (*e.g.,* modified furnace, cullet preheat), and/or post-combustion controls (SNCR or SCR) and thus provide sources some flexibility to choose the control technology that works best for their unique circumstances.

Comment: Multiple commenters responded to EPA's request for comments by stating it is unnecessary and unhelpful for the proposed rule to specify use of particular post-combustion control device. The commenters note that various flat glass furnaces have a variety of combustion and post-combustion control options. Each furnace is different in its design, operations, and finished product produced. The commenters state that it is more appropriate for EPA to establish an emissions limit in the proposed rule than it is for the EPA to specify use of a particular control technology.

Response: In response to these comments, the EPA is not establishing any requirements for affected units to install specific control technologies to meet the emissions limits. The EPA is finalizing the limits as proposed to offer sources some flexibility to choose the control technology that works best for their unique circumstances.

Compliance Assurance Requirements

The EPA proposed to require owners or operators of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces to install, calibrate, maintain and operate a CEMS for the measurement of NO_X emissions discharged. The EPA also solicited comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits. The EPA received numerous comments from the glass industry expressing concern with any requirement to use CEMS at affected units. After review of the comments received and EPA's assessment of practices conducted within the glass manufacturing industry, the EPA is finalizing compliance assurance requirements that allow affected glass manufacturing furnaces to demonstrate compliance through annual testing or use CEMS, or similar alternative monitoring system data in lieu of a performance test. The EPA is also establishing recordkeeping provisions that require owners or operators of affected units to conduct parametric monitoring of fuel use and glass production during performance testing to assure continuous compliance on a 30-operating day rolling average.

Comment: Commenters representing the glass industry stated that a requirement to install and operate CEMS would present significant costs and technical complexities in a situation where emissions can be effectively monitored using stack testing rather than continuous monitoring. Commenters also objected to the EPA's proposal to require CEMS together with semi-annual stack testing. Commenters stated that a requirement to both operate CEMS and conduct semi-annual testing would be unnecessary and excessive and would not provide commensurate benefit unless a facility's emissions are near or above the proposed emissions limit. Commenters requested that owners or operators of affected units be allowed to use alternative monitoring systems, *e.g.,* parametric emissions monitoring. The commenters stated that parametric monitoring requires less initial and ongoing manpower requirements, has lower capital and operating costs than CEMS, does not require spare parts, and is accurate over a mapped range.

Response: The EPA is establishing compliance assurance requirements that provide flexibility to owners or operators of affected units. Compliance with the emissions limits in this final rule may be demonstrated through CEMS or via annual performance test and continuous parametric monitoring. If an affected unit does not use CEMS, the final rule requires the owner or operator to monitor and record stack exhaust gas flow rate, hourly production rate, and stack exhaust temperature during the initial performance test and subsequent annual performance tests to assure compliance with the applicable emissions limit. The owner or operator must then continuously monitor and record those parameters to demonstrate continuous compliance with the NO_X emissions limits. Affected units that operate NO_X CEMS meeting specified requirements may use CEMS data in lieu of performance testing and monitoring of operating parameters. To avoid challenges in scheduling and availability of testing firms, the annual performance test required under this final rule does not have to be performed during the ozone season.

5. Boilers at Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Iron and Steel and Ferroalloys Manufacturing, and Metal Ore Mining facilities

Applicability

The EPA is finalizing regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing industry, Basic Chemical Manufacturing industry, Petroleum and Coal Products Manufacturing industry, Pulp, Paper, and Paperboard Mills industry, and the Metal Ore Mining industry that apply to boilers that have a design capacity of 100 mmBtu/hr or greater. The Non-EGU Screening Assessment memorandum developed in support of Step 3 of our proposal identified emissions from large boilers in certain industries (*i.e.,* those projected to emit more than 100 tpy of NO_X in 2026) as having adverse impacts on downwind receptors. As discussed in the proposed rule, we developed applicability criteria for boilers based on design capacity (*i.e.,* heat input), rather than on potential emissions, because use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. In this final rule, we are establishing the heat input-based applicability criteria described in our proposal, with some adjustments as explained further in this section. Additionally, we have determined that boilers meeting these applicability

[395] EPA, Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing, EPA–453/R–94–037, June 1994.

criteria exist within the following five industries: Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, Pulp, Paper, and Paperboard Mills, Metal Ore Mining, and Iron and Steel Mills and Ferroalloy Manufacturing.

As we explained in the proposed rule, the potential emissions from industrial boilers with a design capacity of 100 mmBtu/hr or greater burning coal, residual or distillate oil, or natural gas can equal or exceed the 100 tpy threshold that we used to identify impactful boilers within the Non-EGU Screening Assessment memorandum. We are finalizing NO_X emissions limits that apply to boilers with design capacities of 100 mmBTU/hr or greater located at any of the five identified industries in any of the 20 covered states with non-EGU emissions reduction obligations. In response to comments on our proposed rule, however, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year and provisions for EPA approval of alternative emissions limits on a case-by-case basis, where specific criteria are met. Additionally, only boilers that combust, on a BTU basis, 90 percent or more of coal, residual or distillate oil, natural gas, or combinations of these fuels are subject to the requirements of these final FIPs.

The EPA has determined that boilers meeting the applicability criteria of this section exist within the five industrial sectors identified in Table VI.C.5–1:

TABLE VI.C.5—1: NON-EGU INDUSTRIES WITH LARGE BOILERS AND ASSOCIATED NAICS CODES

Industry	NAICS code
Basic Chemical Manufacturing	3251xx
Petroleum and Coal Products Manufacturing	3241xx
Pulp, Paper, and Paperboard Mills	3221xx
Iron and Steel and Ferroalloys Manufacturing	3311xx
Metal Ore Mining	2122xx

Comment: Several commenters requested that the EPA establish PTE-based applicability criteria for boilers as it had proposed to do for other non-EGU sectors and stated that using heat input as the basis for determining applicability would result in low-emitting boilers being subject to the final rule's control requirements. Commenters stated that the EPA should provide a low-use exemption for infrequently run units because these units produce a lower amount of emissions.

Response: The EPA is finalizing applicability criteria for boilers based on boiler design capacity for a number of reasons. First, Federal emissions standards applicable to boilers[396] and all of the state RACT rules that we reviewed contain applicability criteria based on boiler design capacity. Second, as explained in the Final Non-EGU Sectors TSD, most boilers with design capacities of 100 mmBTU/hr or greater that are fueled by coal, oil, or gas have the potential to emit 100 tpy or more of NO_X. Thus, use of a boiler design capacity of 100 mmBtu/hr for applicability purposes reasonably approximates the 100 tpy threshold used in the Non-EGU Screening Assessment memorandum to identify impactful boilers. Finally, use of a boiler's design capacity for applicability purposes facilitates applicability determinations given that a boiler's design capacity is, in most cases, clearly indicated by the manufacture on the unit's nameplate.

In response to the comments expressing concern that infrequently-operated boilers would be captured by the EPA's proposed applicability criteria, the EPA is finalizing a low-use exemption for industrial boilers that operate less than 10 percent per year on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years. Such boilers will be exempt from the emissions limits in these FIPs provided they operate less than 10 percent per year, on an hourly basis, based on the three most recent years of use and no more than 20 percent in any one of the three years, but will have recordkeeping obligations. The EPA finds it appropriate to exempt such low-use boilers from the emissions limits in this final rule because the amount of air pollution emitted from a boiler is directly related to its operational hours, and installation of controls on infrequently operated units results in reduced air quality benefits.

Comment: Commenters asked whether the EPA's proposed emissions limits for boilers would apply to emissions units that burn fuels other than coal, residual or distillate oil, or natural gas. For example, one commenter stated that some biomass boilers start up by co-firing oil or gas and that some NO_X controls such as low-NO_X burners (LNB) cannot be used on biomass boilers. The commenter requested clarification on whether boilers burning biomass would be covered by the EPA's proposed requirements. Other commenters noted that some industrial boilers burn natural gas in conjunction with other gaseous fuels, such as hydrogen/methane off-gas and vent gas from various on-site processes, and may not be able to meet the EPA's proposed 0.08 lb/mmBtu NO_X emissions limit for boilers burning natural gas. One commenter stated that it operated a boiler that burns hazardous waste and is subject to 40 CFR part 63, subpart EEE, National Emission Standards for Hazardous Air Pollutants from Hazardous Waste Combustors, and that this boiler uses natural gas for start-up and at other times to stabilize operations but also combusts other fuels such as liquid waste. The commenter asserted that such boilers should not be covered by the final rule.

Response: In recognition and consideration of comments received on our proposal, the EPA is finalizing requirements for boilers that apply only to boilers burning 90 percent or more coal, residual or distillate oil, or natural gas or combinations of these fuels on a heat-input basis. Public commenters presented information indicating that the burning of fuels other than coal, residual or distillate oil, or natural gas at levels exceeding 10 percent may interfere with the functions of the control technologies that may be necessary to the meet the final rule, like SCR. The EPA does not have sufficient information at this time to conclude that units burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost. Therefore, boilers that burn greater than 10 percent fuels other than coal, residual or distillate oil,

[396] *See, e.g.,* 40 CFR 60.44b (subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

natural gas, or combinations of these three fuels are not subject to the emissions limits and other requirements of this final rule.

Comment: Some commenters claimed that the EPA cannot include emissions limits for boilers that burn combinations of coal, residual or distillate oil, and natural gas, because the EPA did not propose limits for such boilers. Other commenters suggested it would be appropriate to establish emissions limits for such boilers as long as the EPA provides criteria for establishing such emissions limits.

Response: The EPA disagrees with the claim that boilers burning combinations of coal, residual or distillate oil, or natural gas cannot be covered by the final FIP because the EPA did not propose specific emissions limits for these boilers and agrees with commenters who stated that the EPA's proposed emissions limits can be extended to such boilers provided the EPA provides criteria for doing so. The applicability criteria in the final rule cover boilers burning combinations of coal, residual or distillate oil, or natural gas and include a methodology for determining the emissions limits for such units based on a simple formula that correlates the amount of heat input expended while burning each fuel with the corresponding emissions limit for that particular fuel. For example, a boiler with a heat input of 85 percent natural gas and 15 percent distillate oil would be subject to an emissions limit derived by multiplying the natural gas emissions limit by 0.85 and adding to that the distillate oil emissions limit multiplied by 0.15. Thus calculated, the NO_X emissions limits for boilers burning combinations of coal, residual or distillate oil, or natural gas are consistent with the NO_X emissions limits identified in our proposed rule for each of these individual fuels.

Emissions Limitations and Rationale

The EPA is finalizing all of the proposed NO_X emissions limits for industrial boilers and adding a formula for calculating emissions limits for multi-fueled units as shown in Table VI.C.5–2. The emissions limits apply to boilers with design capacities of 100 mmBtu/hr or greater located at any of the five industries identified in Table II.A–1 within any of the 20 states covered by the non-EGU requirements of this final rule.

TABLE VI.C.5–2—NO_X EMISSIONS LIMITS FOR BOILERS >100 mmBtu/hr

[Based on a 30-day rolling average]

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20.
Residual oil	0.20.
Distillate oil	0.12.
Natural gas	0.08.
Multi-fueled unit	Limit derived by formula based on heat input contribution from each fuel.

Additional information on the EPA's derivation of these proposed emissions rates for boilers is provided in the Final Non-EGU Sectors TSD.

Comment: Some commenters noted that many boilers are already subject to other state and Federal controls, and that programs such as RACT, NSR, BACT, NSPS, and maximum achievable control technology (MACT) are all achieving emissions reductions from boilers.

Response: The EPA acknowledges that some affected units may already be meeting the emissions limits established in this rule as a result of controls installed to comply with other regulatory programs, such as the CAA's RACT requirements. However, emissions from the universe of boilers subject to the applicability requirements of this final rule are not being uniformly reduced by these programs to the same extent that the limits we are adopting will require, nor for the same reason, which is to mitigate the impact of emissions from upwind sources on downwind locations that are experiencing air quality problems. The EPA has determined that the limits we are finalizing in this action are readily achievable and are already required in practice in many parts of the country.

Regarding RACT controls, some of the sources covered by the final rule are not subject to RACT requirements because RACT is only applicable to sources located in ozone nonattainment areas and in the OTR, and many sources covered by the final rule are not located within such jurisdictions. Regarding sources that are subject to RACT, we note that unlike RACT requirements applicable to sources of VOCs, where a majority of such sources are covered by state RACT rules adopted to conform with uniform ''presumptive'' limits contained within the EPA's Control Technique Guidelines (CTGs), in most cases presumptive NO_X emissions limits have not been established for industrial sources of this pollutant. In light of this, NO_X RACT requirements are primarily determined on a state-by-state basis and exhibit a range of stringencies as determined by each state. Additionally, RACT requirements tend to become more stringent with the passage of time as existing control options are improved, and new options become available. Thus, older RACT determinations may not be as stringent as more recent determinations made for similar equipment types. As noted in our proposal, we based our NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired industrial boilers on RACT limits that are already in place in many areas of the country.

Regarding NSR control requirements, we note that the NSR program was created by the 1977 amendments to the CAA and applies only to new or modified stationary sources. Many of the boilers covered by the applicability requirement of this final rule were initially installed or last modified prior to 1977 and have not undergone NSR analysis, such as a BACT analysis for sources located within an attainment area or a LAER analysis for sources located within nonattainment areas. Additionally, BACT and LAER determinations made many years ago are not likely to be as stringent as more recent determinations.

Regarding NSPS requirements, 40 CFR part 60, subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, contains NO_X emissions limits for boilers with capacities of 100 mmBTU/hr or greater that were constructed or modified after June 19, 1984, and so boilers constructed or modified prior to that date are not subject to its requirements. Additionally, the limits for coal, residual or distillate oil, and gas-fired units are not as stringent as more recent limits adopted by states pursuant to RACT control obligations.

Lastly, MACT controls are primarily designed to reduce emissions of hazardous air pollutants, not to reduce NO_X emissions. We anticipate the MACT program's boiler tune-up requirement should reduce NO_X emissions to some extent, but not to the extent that compliance with the limits adopted within this final rule will achieve.

Comment: One commenter noted that a 2017 OTC survey found that boilers, including those used in the paper products, chemical, and petroleum industries, are already required to achieve more stringent limits, and pointed to limits for distillate oil that are lower than what the EPA considered in developing the proposal. The commenter also noted that California's South Coast Air Quality Management District has adopted a facility-wide NO_X emissions limit of 0.03 lb/mmBtu at petroleum refineries. The commenter noted that CEMs data shows a residual oil-fired boiler at the Ravenswood Steam Plant in New York achieves an average NO_X emissions rate of 0.0716 lb NO_X/MMBtu and that CEMS data shows that a gas-fired boiler in Johnsonville, Tennessee, achieves an average NO_X emissions rate of 0.0058 lb NO_X/mmBTU. Regarding coal-fired boilers, the commenter stated that a coal boiler at the Ingredion Incorporated Argo Plant in Illinois achieves an average NO_X emissions rate of 0.1153 lb NO_X/MMBtu with selective non-catalytic control technology, and the Axiall Corporation facility in West Virginia achieves a 0.1162 lb/mmBtu using low-NO_X burner technology with overfire air. The commenter also noted that more than half of the gas-fired boilers included in the air markets program database already emit NO_X at rates below the EPA's proposed emissions rate, and that the RACT/BACT/LAER Clearinghouse (RBLC) shows more stringent limits for gas boilers than the limits the EPA proposed, with many facilities being required to meet a NO_X limit of less than 0.0400 lb/mmBtu.

Response: The EPA's intent was not to set the NO_X emissions limits for coal, residual or distillate oil, and natural gas-fired boilers to match the lowest levels required elsewhere by state or local authorities, but rather to establish limits that are commensurate with broadly applicable RACT limits currently in place in a number of states as noted within our proposal. The limits we selected were not the most stringent of the state RACT rules we reviewed but were relatively close to that value. We did not select the most stringent limits because such limits may reflect case-specific technological and economic feasibility considerations that do not apply more broadly across the industry. Furthermore, although the EPA acknowledges that some industrial boilers powered by coal, residual or distillate oil, natural gas, or combinations of these fuels can meet very low NO_X emissions limits as noted by the commenter, it is unlikely that all such units could meet these limits given case-specific considerations such as boiler design and operation, some of which limit the types of control technology that may be available to a particular unit.

a. Coal-Fired Industrial Boilers

As we proposed, coal-fired industrial boilers subject to the applicability requirements of this section are required to meet a NO_X emissions limit of 0.2 lb/mmBtu on a 30-day rolling average basis. Various forms of combustion and post-combustion NO_X control technology exist that should enable most facilities to retrofit with equipment to meet this emissions limit. As we explained in our proposal, many states containing ozone nonattainment areas or located within the OTR have already adopted RACT emissions limits similar to or more stringent than the limits in this final rule, and most of those RACT limits apply statewide and extend to boilers located at commercial and institutional facilities, not just to boilers located in the industrial sector.

Comment: One commenter noted that the coal-fired boilers it operates already use combustion controls to reduce NO_X emissions and contended that the effectiveness of SNCR on these boilers is unknown but would likely be on the low end of the control effectiveness range because they experience variable loads, which would compromise the proper functioning of an SNCR control system. The commenter stated that the only way their coal-fired boilers would be able to comply with the EPA's proposed NO_X limit would be to install SCR. The commenter added that for coal-fired industrial boilers with a heat input rating of 100 MMBtu/hr or more, a review of the available RBLC records indicates that out of the 23 RBLC entries identified, nine units (less than half) were subject to an emissions limit at or below 0.2 lb/mmBtu, and eight of these nine units were equipped with SNCR. The commenter stated that based on a review of the available data in the RBLC and given the technical difficulties and low control efficiencies when applying SNCR to swing boilers, the EPA's proposed limit for coal firing does not appear achievable for industrial coal-fired boilers that experience load swings unless SCR is installed. Other commenters stated that while there have been recent advancements in SNCR technology, such as the setting up of multiple injection grids and the addition of sophisticated CEMs-based feedback loops, implementing SNCR on industrial load-following boilers continues to pose several technical challenges, including lack of achievement of optimal temperature range for the reduction reactions to successfully complete, and inadequate reagent dispersion in the injection region due to boiler design which can lead to significant amounts of unreacted ammonia exhausted to the atmosphere (*i.e.,* large ammonia slip). The commenter noted that at least one pulp mill boiler had to abandon its SNCR system due to problems caused by poor dispersion of the reagent within the boiler, and that SNCR has yet to be successfully demonstrated for a pulp mill boiler with constant swing loads.

Response: To the extent the commenter's concerns pertain primarily to SNCR control technology, we note that the final rule does not mandate the use of any particular type of control technology and that other types of control equipment such as SCR should be examined as a means for meeting the final emissions limits. The EPA acknowledges that some coal-fired industrial boilers subject to this section of the final rule may need to install SCR to meet the NO_X emissions limits. This is reflected in our evaluation of costs for the non-EGU sector contained within the Non-EGU Screening Assessment memorandum and the cost calculations for the final rule discussed in section V and the *Memo to Docket—Non-EGU Applicability Requirements and Estimate Emissions Reductions and Costs.* We note that although the RBLC contains information on emissions limits and control technology for some units, it only provides information on a relatively small number of units subject to NO_X emissions limits and operating NO_X controls. Additionally, our final rule provides an exemption for units that operate infrequently (*i.e.,* ''low-use boilers''), and also allows a facility owner or operator to submit a request for a case-by-case alternative emissions limit in cases where compliance with the emissions limit in this final rule is technically impossible or would result in extreme economic hardship. We note that non-EGU boilers share many similarities with EGU boilers, many of which already operate SCR to control NO_X emissions or will be required to install and operate SCR systems under the requirements for EGUs contained in this final rule. Lastly, we note that information collected during the development of updates to the EPA's MACT requirements for industrial, commercial, and institutional (ICI) boilers indicates that over 150 ICI boilers have installed SCR control systems to reduce their NO_X emissions. This information is available in the docket for this final rule.

All affected units must install and operate NO_X control equipment as necessary to meet the applicable emissions limits in the final rule, except that if the owner or operator requests, and the EPA approves, a case-by-case emissions limit based on a showing of technical impossibility or extreme economic hardship, the affected unit would be required to comply with the EPA-approved case-by-case emissions limit instead.

b. Residual or Distillate Oil-Fired Industrial Boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. We proposed a NO_X emissions limit of 0.2 lb/mmBtu [397] for residual oil-fired boilers and proposed a NO_X emissions limit of 0.12 lb/mmBtu for distillate oil-fired boilers. We are finalizing both limits as proposed, based on a 30-day rolling average. As with coal-fired industrial boilers, a number of combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet these emissions limits, and the Final Non-EGU Sectors TSD identifies numerous states that have already adopted emissions limits similar to the limits in this final rule. There are relatively few boilers fueled by residual or distillate oil within the industries affected by this final rule that meet the applicability criteria of this section, and we received relatively few comments regarding our proposed emissions limits for them.

c. Natural Gas-Fired Industrial Boilers

We proposed a NO_X emissions limit of 0.08 lb/mmBtu based on a 30-day rolling average for natural gas-fired boilers meeting the applicability criteria of this section, and we are finalizing this emissions limit and averaging time as proposed. As explained in our proposal, numerous combustion and post-combustion NO_X control technologies exist that should generally enable facilities meeting the applicability criteria of this section to meet this emissions limit. Additionally, many states have already adopted emissions limits similar to the emissions limit in this final rule, and some natural gas-fired industrial boilers may be able to meet the 0.08 lb/mmBtu emissions limit by modifying existing NO_X control equipment installed to meet the requirements in 40 CFR 60.44b (subpart Db of 40 CFR part 60, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), which already requires that natural gas-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/MMBtu.

Compliance Assurance Requirements

We proposed compliance provisions for boilers subject to the requirements of this section similar to the emissions monitoring requirements found in 40 CFR 60.45 (subpart D of 40 CFR part 60, Standards of Performance for Fossil-Fuel-Fired Steam Generators). Those requirements include, among other provisions, the performance of an initial compliance test and installation of a CEMS unless the initial performance test indicates the unit's emissions rate is 70 percent or less of the emissions limit in this final rule. We received a number of comments on this portion of our proposal and provide responses to some of these comments in the following paragraphs. Our full responses to comments are provided in the response to comments document included in the docket for this action.

Comment: A number of commenters stated that CEMS monitoring is too expensive and unnecessary for ensuring compliance with the emissions limits for boilers and requested that alternative monitoring techniques be allowed.

Response: The EPA acknowledges that the installation and operation of CEMs systems is more expensive than other monitoring techniques and may not be necessary for smaller sized boilers that typically produce less emissions than larger ones. In response to these comments, we have modified the monitoring requirements in the final rule such that boilers rated with heat-input capacities less than 250 mmBTU/hr can demonstrate compliance by conducting an annual stack test as an alternative to monitoring using a CEMs system and by complying with the provisions of a monitoring plan meeting specific criteria that enables the facility owner or operator to demonstrate continuous compliance with the emissions limits of this final rule.

Comment: One commenter stated that the proposed reporting obligations require the submittal of excess emissions reports, continuous monitoring, and quarterly emissions reports. The commenter suggested that since the NO_X emissions standards only apply during the ozone season (May 1–September 30), the reporting requirements should only apply during the second and third quarters of the year and should require that only emissions and monitoring data from this time period be included in these reports.

Response: In response to these comments, the EPA is finalizing recordkeeping, monitoring, and reporting requirements that are designed to ensure compliance with the applicable emissions limits only during the ozone season. Additionally, the final rule requires annual reports rather than the proposed quarterly reports as annual reports are adequate to determine compliance with the emissions limits during the ozone season.

Comment: A number of commenters stated that some of their boilers that may potentially be subject to a final FIP already have a NO_X CEMS installed and requested that the EPA clarify whether a 30-day initial compliance test is required in such cases.

Response: The EPA's final rule provides that in instances where a boiler meeting the applicability requirements of this section has already installed a NO_X CEMs that meets the requirements for such equipment located within 40 CFR 60.13 or 40 CFR part 75, Continuous Emissions Monitoring, pursuant to a federally enforceable requirement, a 30-day initial compliance test is not required.

Comment: One commenter stated that § 52.45(d) of the EPA's proposed rule included requirements to complete an initial 30-day compliance test within 90 days of installing pollution control equipment but did not specify whether the test must be complete prior to the May 1, 2026, ozone season or by some later date.

Response: In response to this comment, the EPA is finalizing provisions requiring that initial compliance tests occur prior to the May 1, 2026 compliance date.

6. Municipal Waste Combustors

Applicability

The EPA is finalizing regulatory requirements that apply to municipal solid waste combustors located in a state subject to the non-EGU requirements of this final rule (*i.e.,* the 20 states with linkages that persist in 2026 as identified in section II.B) and

[397] Section 52.45(c) of the regulatory text in our proposed rule identified a proposed emissions limit of 0.15 lb/mmBtu for residual oil-fired boilers, but the emissions limit that we intended to propose for this equipment and discussed both in the preamble to the proposed rule and in the TSD supporting the proposed rule was 0.20 lb/mmBtu.

that combust greater than or equal to 250 tons per day of municipal solid waste (''affected units''). *See* 40 CFR 52.46(d) for guidelines on calculating municipal waste combustor unit capacity. This applicability threshold was supported by commenters and is consistent with the applicability criteria in 40 CFR part 60, subpart Eb, Standards of Performance for New Stationary Sources and Emission Guidelines for Existing Sources: Large Municipal Waste Combustors. State RACT rules for MWCs and the OTC MWC report similarly define large MWC units as units with a combustion capacity greater than or equal to 250 tons per day.

Across the 20 states subject to the non-EGU requirements, this applicability threshold captures 28 MWC facilities with a total of 80 affected units. The identified affected units include mass burn waterwall units, mass burn rotary waterwall units, refuse derived fuel (RDF) units, and one CLEERGAS™ (''Covanta Low Emissions Energy Recovery Gasification'') modular system.[398] The EPA analyzed actual emissions from the facilities captured by this threshold and found that on average, a unit with a design capacity of 250 tons per day has a PTE of approximately 138 tons per year,[399] which is similar to the PTE threshold applied to other non-EGU sources under this rulemaking.

Emissions Limitations and Rationale

Based on the available information for this industry, including information provided during the public comment period, the OTC MWC Report, a review of State and local RACT rules that apply to MWCs, and active air permits issued to MWCs, the EPA is finalizing the following emissions limits for municipal solid waste combustors.

TABLE VI.C.6–1—NO_X EMISSIONS LIMITS FOR LARGE MUNICIPAL WASTE COMBUSTORS

NO_X Limit (ppmvd) corrected to 7 percent oxygen	Averaging period
110	24-hour.
105	30-day.

At proposal, the EPA noted that the NO_X limits for large MWCs constructed on or before September 20, 1994 under NSPS subpart Cb are found within Tables 1 and 2 of 40 CFR 60.39b and range from 165 to 250 ppm depending on the combustor design type. The NO_X limits for large MWCs constructed after September 20, 1994 or for which modification or reconstruction is commenced after June 19, 1996 under NSPS subpart Eb are found at 40 CFR 60.52b(d) and are 180 ppm during a unit's first year of operation and 150 ppm afterwards, applicable across all combustor types. These limits correspond to NO_X emissions rates of 0.31 and 0.26 lb/mmBtu, respectively. In reviewing active air permits for MWCs, the EPA found that most MWCs are meeting emissions limits similar to those reflected in the applicable NSPS.[400]

The EPA also cited the OTC's MWC report that evaluated the emissions reduction potential of large MWCs located in the OTR from two different control levels, one based on a NO_X concentration of 105 to 110 ppm, and another based on a limit of 130 ppm. The OTC MWC report found that a control level of 105 ppmvd on a 30-day rolling average basis and a 110 ppmvd on a 24-hour block averaging period would reduce NO_X emissions from MWCs by approximately 7,300 tons annually, and that a limit of 130 ppmvd on a 30 day-average could achieve a 4,000 ton reduction. The OTR MWC Report noted that at the time of publication, eight MWC units were already subject to permit limits of 110 ppm, seven in Virginia, and one in Florida. In consideration of control costs, the report cited multiple studies evaluating MWCs similar in design to the large MWCs in the OTR and found NO_X reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NO_X reduced.

To further inform the EPA's consideration of emissions limits for MWCs, the EPA requested comment on the emissions limit and averaging time MWCs should be required to meet, and specifically whether the EPA should adopt emissions rates of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Comment: The agency received several comments regarding emissions limits and averaging time for MWCs. Many commenters asserted that the EPA should set a 24-hour emissions limit no higher than 110 ppm, noting that recent studies have shown that there are a variety of technologies that can help a wide range of MWC types achieve this limit at costs that are significantly below the $7,500/ton cost effectiveness threshold that the EPA identified at proposal. Some commenters confirmed the accuracy of the OTC workgroup's estimated cost of controls for reducing NO_X emissions from MWCs of $2,900 to $6,600 while others stated that the cost of controls is well below $7,500. One commenter asserted that the EPA should set a 24-hour NO_X emissions limit of 50 ppmvd for MWCs, which could be achieved by the installation of SCR technology. Alternatively, the commenters stated that the EPA should set a 24-hour emissions limit no higher than 110 ppm based on less effective, though still widely available, control technology. Although some commenters stated that MWCs should not be included in the rulemaking, no commenters specifically identified units or categories of units that could not achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis.

Response: The EPA recognizes that there have been instances where MWCs have installed SCR and achieved emissions rates of 50 ppmvd on a 24-hr averaging basis and 45 ppmvd on a 30-day rolling averaging basis with cost effectiveness estimates around $10,296/ton to $12,779/ton of NO_X reduced. Given uncertainties pertaining to whether SCR can be installed on all types of MWCs, the EPA has decided not to establish emissions limits as low as 50 ppmvd for MWCs using SCR at this time. However, as generally supported by most commenters, the EPA is finalizing emissions limits of 105 ppmvd at 7 percent oxygen (O_2) on a 30-day rolling average and 110 ppmvd at 7 percent O_2 on a 24-hour block average that apply at all times except during periods of startup and shutdown. The EPA recognizes that the final emissions limits for steady-state operations cannot be achieved during periods of startup, shutdown, and malfunction. This is primarily due to the fact that during periods of startup and shutdown, additional ambient air is introduced into the units, resulting in higher oxygen concentrations. Therefore, the EPA is finalizing provisions applicable during periods of startup and shutdown that do not require correction of CEMS data to 7 percent oxygen but do require that such data be measured at stack oxygen content. This approach is consistent with EPA regulations applicable during startup and shutdown periods for other solid-waste incinerators under the NSPS for Commercial and Industrial Solid Waste Incineration Units. *See* 40 CFR part 60, subparts CCCC and DDDD.

[398] *See* the Final Non-EGU Sectors TSD for additional information on this inventory.

[399] *See* the Final Non-EGU Sectors TSD for additional information on the calculation of PTE for large MWCs.

[400] For further discussion of the permits reviewed, see the Final Non-EGU Sectors TSD.

Information received from public commenters generally aligned with the results from studies showing that the emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis can be reached using ASNCR or low NO_X technology in addition to SNCR.[401] The EPA recognizes that not all units can implement low NO_X technology, including those using Aireal grate technology, those operating RFD units, and those with rotary combustor units. Of the 80 affected MWC units that the EPA identified, nine units across two facilities are classified as rotary combustors, four units at a single facility are classified as RDF, and no units captured are classified as using Aireal grate technology. One affected unit is classified as CLEERGAS gasification while the remaining 64 affected units are classified as mass burn waterwall combustors, which have not been explicitly identified as units unable to install low NO_X technology. For those units unable to install low NO_X technology or SNCR, the EPA has identified ASCNR as an alternative control technology that has been shown to enable units to achieve emissions limits of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis, either as a new retrofit technology or as a significant upgrade to existing SNCR. The EPA finds that the availability of ASNCR or SNCR and low NO_X burners provides sufficient flexibility for MWCs to meet the emissions limits in the final rule, especially considering 74 of the 80 affected units already have SNCR installed. Although there is uncertainty on the cost effectiveness of ASNCR for achieving significant NO_X reductions in small MWCs, small MWCs that combust less than 250 tons per day of municipal solid waste are not included in this rulemaking.

While commenters noted discrepancies across cost effectiveness values for specific types of control technology, no commenters specifically indicated that emissions control technology could not be cost effectively installed on large MWCs to achieve an emissions limit of 105 ppmvd on a 30-day rolling averaging basis and 110 ppmvd on a 24-hour block averaging basis. Studies show that these limits can be achieved through a variety of emissions controls, including ASNCR and the addition of low NO_X technology to existing SNCR.[402] Of the 80 MWC units subject to this rule, 55 units already have SNCR installed, 16 units already have SNCR and low NO_X technology installed, and three units already have ASNCR installed. Applying the cost values provided in the OTC's MWC report to the MWC inventory in section 7 of the Final Non-EGU Sectors TSD, the estimated weighted average cost effectiveness of applying advanced SNCR to units with and without existing SNCR and adding low NO_X technology to eligible units with SNCR was found to be approximately $7,929.02/ton.[403] This value is in line with the control technology costs for other non-EGU sectors and the EGU costs associated with this final rule.

Compliance Assurance Requirements

In this final rule, the EPA is establishing compliance requirements for MWCs similar to the NSPS requirements for large MWCs under 40 CFR part 60, subpart Eb. Those requirements include, among other provisions, the performance of an initial performance test and installation of a CEMS. At proposal, the EPA requested comment on whether it would be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs under applicable NSPS or other requirements.

Comment: Some commenters noted that all large MWCs are already required to use CEMS to demonstrate compliance with NO_X limits under the NSPS program. These commenters asserted that the EPA should improve electronic reporting requirements beyond current requirements in the NSPS. The commenters suggested that an owner or operator of an MWC subject to a limit under the final rule should be required to report NO_X CEMS data electronically at least annually to the EPA's CEDRI and any other database that the EPA will utilize when considering revisions to the NSPS for large MWCs. The commenters asserted that MWC operators should be required to report NO_X CEMS data to the EPA's Clean Air Markets database, to allow the public access to MWC CEMS data on a large scale for the first time.

Response: The EPA is finalizing provisions that require MWCs subject to the requirements of this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. This is consistent with NSPS requirements for large MWCs under 40 CFR part 60, subparts Ea and Eb, and state RACT rules that are applicable to MWCs in many of the states covered under this rulemaking.[404] Additionally, each emissions unit will be required to conduct an initial performance test. With regard to electronic reporting, the final rule requires performance tests and reports, including CEMS data, to be submitted to CEDRI, as required for all non-EGU industries covered by this final rule.

D. Submitting a SIP

A state may submit a SIP at any time to address CAA requirements that are covered by a FIP, and if the EPA approves the SIP it would replace the FIP, in whole or in part, as appropriate. As discussed in this section, states may opt for one of several alternatives that the EPA has provided to take over all or portions of the FIP. However, as discussed in greater detail further in this section, the EPA also recognizes that states retain the discretion to develop SIPs to replace a FIP under approaches that differ from those the EPA has finalized.

The EPA has established certain specialized provisions for replacing FIPs with SIPs within all the CSAPR trading programs, including the use of so-called ''abbreviated SIPs'' and ''full SIPs,'' *see* 40 CFR 52.38(a)(4) and (5) and (b)(4), (5), (8), (9), (11), and (12); 40 CFR 52.39(e), (f), (h), and (i). For a state to remove all FIP provisions through an approved SIP revision, a state would need to address all of the required reductions addressed by the FIP for that state, *i.e.,* reductions achieved through both EGU control and non-EGU control,

[401] The only demonstrated use of low NO_X technology in addition to SNCR at MWC facilities is at Covanta facilities using Covanta's proprietary low NO_X combustion system (LN™). For the purpose of this rule, EPA is assuming Covanta facilities will take advantage of this technology and others will use ASNCR. However, other iterations of low NO_X technology could become available, or facilities could work with Covanta to apply this technology to their units.

[402] *See* OTC MWC Report at 6–7; Trinity Consultants, *Project Report Covanta Alexandria/Arlington, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Trinity Consultants, *Project Report Covanta Fairfax, Inc., Reasonably Available Control Technology Determination for NO_X* (September 2017); Babcock Power Environmental, *Waste to Energy NO_X* Feasibility Study, Prepared for: Wheelabrator Technologies Baltimore Waste to Energy Facility Baltimore, MD (February 20, 2020); White, M., Goff, S., Deduck, S., Gohlke, O., *New Process for Achieving Very Low NO_X, Proceedings of the 17th Annual North American Waste-to-Energy Conference, NAWTEC17* (May 2009); Letter from the State of New Jersey to Michael Klein, In Rreference to Covanta Energy Group, Inc. Essex County Resource Recovery Facility, Newark Annual Stack Test Program (March 14, 2019).

[403] See Final Non-EGU Sectors TSD for more information on these cost effectiveness estimates were generated.

[404] For examples of RACT provisions applicable to MWCs that require CEMS, see Regulations of Connecticut State Agencies section 22a–174–22e; and Virginia Administrative Code section 5–40–6730, subsection (D).

as applicable to that state. Additionally, tribes in Indian country within the geographic scope of this rule may elect to work with EPA under the Tribal Authority Rule to replace the FIP for areas of Indian country, in whole or in part, with a tribal implementation plan or reasonably severable portions of a tribal implementation plan.

Under the FIPs for the 22 states whose EGUs are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with the modifications finalized in this rule, EPA continues to offer ''abbreviated'' and ''full'' SIP options for states. An ''abbreviated SIP'' allows a state to submit a SIP revision that establishes state-determined allowance allocation provisions replacing the default FIP allocation provisions but leaving the remaining FIP provisions in place. A ''full SIP'' allows a state to adopt a trading program meeting certain requirements that allow sources in the state to continue to use the EPA-administered trading program through an approved SIP revision, rather than a FIP. In addition, as under past CSAPR rulemakings, states have the option to adopt state-determined allowance allocations for existing units for the second control period under this rule—in this case, the 2024 control period—through streamlined SIP revisions. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

Comments: Some commenters alleged that by taking this action, EPA is depriving states of the ability to develop SIPs to implement good neighbor obligations for the 2015 ozone NAAQS or from choosing their own compliance strategies. Commenters also claimed that the EPA cannot require states to implement emissions reductions equivalent to the emissions control stringency that the EPA determined at Step 3 if their proposed SIPs are otherwise shown to be adequate to eliminate significant contribution. Other commenters raised concerns that the trading program enhancements for EGUs made it too uncertain what a state could develop as an approvable replacement SIP. At least one commenter argued that the EPA must give states a single, mass-based emissions budget so that they can understand how to replace the FIP with a SIP.

Response: The EPA disagrees that it is depriving States of the opportunity to replace the FIP with a SIP or preventing states from targeting alternative emissions reductions strategies that can be shown to be equivalent to the FIP. States have always possessed the authority and the opportunity to revise their SIPs at any point. The EPA has repeatedly emphasized that states are free to develop a SIP revision to replace a transport FIP and submit that to the EPA for approval, and this remains true. *See* 87 FR 20036, 20051 (April 6, 2022); 86 FR 23054, 23062 (April 30, 2021); 81 FR 74504, 74506 (Oct. 26, 2016). In the FIP proposal, as in prior transport actions, the EPA discussed a number of ways in which states could take over or replace a FIP, *see* 87 FR 20036, 20149–51 (section VII.D: ''Submitting A SIP''); *see also id.* at 20040 (noting as one purpose in proposing the FIP that ''this proposal will provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes necessary to eliminate significant contribution''). The EPA provides further guidance on submitting SIPs in this section. If, and when, the EPA receives a SIP submission that satisfies the requirements of CAA section 110(a)(2)(D)(i)(I) and 110(l), the Agency will take action to approve those SIP submissions and withdraw the FIP.

At the outset, we note that the Agency does not anticipate revisiting its findings at Steps 1 or 2 of the transport framework. Those findings establish that the projected baseline anthropogenic emissions from these states contribute to downwind nonattainment or maintenance receptors in 2023, and, for certain states, that contribution continues through 2026. Those represent critical analytical years for downwind areas as they are the last full ozone season before the Moderate and Serious area attainment dates. Those findings, for those years, establish the basis for an upwind state's linkage, from which we proceed to evaluate emissions control opportunities and their implementation at Steps 3 and 4.

We cannot prejudge now whether state submissions to replace the EPA's FIP will be approvable, but we note a number of statutory and implementation considerations states should be aware of if designing a replacement SIP. We have demonstrated that the EPA's transport FIP is adequate to eliminate significant contribution to downwind air quality problems for purposes of the 2015 ozone NAAQS, and that the FIP does not result in overcontrol. The level of reductions required by the FIP therefore provides an important benchmark for states in evaluating the equivalency of possible replacement SIPs. As discussed in more detail in this section, in order to comply with their obligation under CAA section 110(a)(2)(D)(i)(I), we generally anticipate that states seeking to replace the FIP with a SIP that takes an alternative approach would need to establish, at a minimum, an equivalent level of emissions reduction to what the FIP requires at Step 3, and any such replacement SIP will need to comply with CAA section 110(*l*).

The concept of equivalency is important for the state to consider. Under CAA section 110(l), ''the Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment . . . or any other applicable requirement of this chapter.'' Section 110(l) applies to all CAA requirements, including 110(a)(2)(D) requirements relating to interstate transport. The EPA interprets section 110(l) such that states have two main options to make a noninterference demonstration. First, the state could demonstrate that emissions reductions removed from the SIP are replaced with new control measures that achieve equivalent or greater emissions reductions. Thus, a 110(l) analysis would generally need to show that the SIP revision, or, in this case, a potential SIP submission replacing an existing FIP, will not interfere with any area's ability to continue to attain or maintain the affected NAAQS or other CAA requirements. The EPA further has interpreted section 110(l) as requiring such substitute measures to be quantifiable, permanent, and enforceable, among other considerations. For section 110(l) purposes, ''permanent'' means the state cannot modify or remove the substitute measure without EPA review and approval. Second, the state could conduct air quality modeling or develop an attainment or maintenance demonstration based on the EPA's most recent technical guidance to show that, even without the control measure or with the control measure in its modified form, significant contribution from the state would continue to be prohibited as the Act requires. As discussed further in this section, for purposes of interstate ozone transport, such an analysis entails important questions of consistency and equity among states for resolving air quality problems that the EPA would need to carefully evaluate.[405]

[405] For instance, future circumstances in which the receptor or receptors to which a state is linked come fully into attainment or to which the upwind state's linkage drops below 1 percent of the NAAQS would likely not, solely on those grounds, be sufficient to relax transport requirements established by the FIP or justify approving a less stringent SIP. First, the emissions reductions achieved by the FIP are part of the reason that a receptor may come into attainment or a linkage may drop below 1 percent of the NAAQS. Simply

Continued

In the EPA's experience implementing the CAA criteria pollutant program, reductions arising from the good neighbor provision have been critically important to the improvement of air quality in downwind areas struggling with attainment and maintenance of the NAAQS, and states' reliance on good neighbor FIP reductions will need to be taken into account in any replacement SIP. In order for a nonattainment area to be redesignated to attainment, the CAA requires not only that an area attain the standard, but also the Administrator must determine ''that the improvement in air quality is due to permanent and enforceable reductions in emissions resulting from implementation of the applicable implementation plan and applicable Federal air pollutant control regulations and other permanent and enforceable reductions.'' CAA section 107(d)(3)(E)(i) and (iii). Many nonattainment areas across the country that have attained various $PM_{2.5}$ and ozone NAAQS have done so in part due to the imposition of Federal good neighbor emissions control measures, and, per CAA section 107(d)(3)(E)(iii), states have specifically relied on the emissions reductions required by those programs in order to be redesignated to attainment. *See, e.g.,* 84 FR 8422, 8425 (March 8, 2019) (noting that ''[a]t least 140 EPA final actions redesignating areas in 20 states to attainment with an ozone NAAQS or a fine particulate matter ($PM_{2.5}$) NAAQS—because NO_X is a precursor to $PM_{2.5}$ as well as ozone—have relied in part on the NO_X SIP Call's emissions reductions''); *see also Sierra Club* v. *EPA,* 774 F.3d 383, 397–99 (7th Cir. 2014) (upholding EPA's approval of a redesignation, and specifically EPA's determination that reductions from Federal good neighbor transport trading programs could reasonably be considered ''permanent and enforceable'' under the statute); *Sierra Club* v. *EPA,* 793 F.3d 656, 665–68 (6th Cir. 2015) (same). States seeking area redesignations are also required under CAA section 107(d)(3)(E)(iv) to develop revisions to their state implementation plans that provide for maintenance of the NAAQS. In so doing, states develop air quality modeling, in which they project future air quality based on emissions inputs that account for enforceable emissions reductions, or states project emissions in the future relative to emissions in an attainment year, showing that the future emissions (which, again, account for on-the-books, enforceable emissions limits) do not exceed emissions in the baseline attainment year. *See* ''Procedures for Processing Requests to Redesignate Areas to Attainment,'' Memo from John Calcagni to EPA Regions, September 4, 1992, at 9. Reductions required by Federal good neighbor programs may therefore also be relied upon by states seeking area redesignations in the context of how states demonstrate that areas will maintain the NAAQS.

We anticipate that air quality in areas struggling to attain and maintain the 2015 ozone NAAQS will improve due to the emissions reductions required by EPA's FIP. We also anticipate that, consistent with EPA's historical experience implementing the NAAQS and acting on state requests for nonattainment area redesignations, emissions reductions associated with EPA's transport FIP for the 2015 ozone NAAQS are likely to be a critical component in those requests for redesignation. Where states have relied and are relying on the FIP's reductions in order to attain and maintain the NAAQS, EPA will look very critically at any replacement SIP that appears to fall short of equivalent emissions reductions—in terms of the level of reductions or the permanence of those reductions.

Finally, we disagree with commenters that the absence of fixed, mass-based emissions budgets for each state make it impossible to replace the FIP with an equivalent SIP. In the case of the trading program enhancements for EGUs, the EPA recognizes that the dynamic budgeting methodology will generally function to impose a continuous incentive on relevant EGUs to continue to implement the emissions control strategies determined at Step 3. Further, the backstop rate and banking recalibration enhancements also are designed to ensure that EGUs implement emissions controls consistent with Step 3 determinations on a continuous basis throughout each ozone season. As explained in section V.D.4 of this document, these aspects of the trading program do not in themselves introduce an overcontrol concern. Nonetheless, consistent with the more general principles discussed in this section with respect to the potential bases on which states may replace the FIP with SIPs, we reserve judgment at this time on whether some future demonstration could successfully establish that revision of the FIP or its replacement with a SIP could be acceptable even if the way that significant contribution is eliminated is through means that differ from the trading program enhancements included for EGUs in this action. As discussed further in this section, a state may choose to withdraw its EGUs from the trading program and instead subject those EGUs to daily emissions rates commensurate with installation and optimization of state-of-the-art combustion and post-combustion controls as the EPA determined at Step 3. Likewise, states are free to explore an alternative set of emissions controls on non-EGU industrial sources (or other sources in the state), so long as they can demonstrate that an equivalent amount of emissions is eliminated. In any case, we need not resolve these questions here. The EPA, in promulgating a FIP, is not obligated to identify each way a state could replace it with a SIP revision. Several options are discussed further in this section, and, as always, EPA Regional Offices will work closely with states who wish to explore these options or other alternatives.

1. SIP Option To Modify Allocations for 2024 Under EGU Trading Program

As with the start of past CSAPR rulemakings, the EPA is finalizing the option to allow a state to use a similar process to submit a SIP revision establishing allowance allocations for existing EGU units in the state for the second control period of the new requirements, *i.e.,* in 2024, to replace the EPA-determined default allocations. A state must submit a letter to EPA by August 4, 2023, indicating its intent to submit a complete SIP revision by September 1, 2023. The SIP would provide in an EPA-prescribed format a list of existing units within the state and their allocations for the 2024 control period. If a state does not submit a letter of intent to submit a SIP revision, the EPA-determined default allocations will be recorded by September 5, 2023. If a state submits a timely letter of intent but fails to submit a SIP revision, the EPA-determined default allocations will be recorded by September 15, 2023. If a state submits a timely letter of intent

removing emissions control requirements the moment this occurs is illogical, since those reductions are part of the solution by which the attaining air quality was achieved or the linkage was resolved. *See* CAA section 107(d)(3)(E)(iii) (areas cannot be redesignated unless based on permanent and enforceable reductions); *see also Wisconsin,* 938 F.3d at 324–25 (explaining that upwind states are held to a contribution standard, not a but-for causation standard and thus cannot escape good neighbor obligations on the basis that other emissions ''cause'' the NAAQS to be exceeded). There is a risk of inconsistency and inequity in removing any requirements in this manner in that any increase in emissions that could occur in one upwind state would likely need to be reviewed in relation to the obligations other upwind states would continue to meet. Further, any such relaxation in upwind state requirements could then unreasonably shift the burden for maintaining air quality onto the downwind states where receptors are located. These issues may entail complex state- or case-specific analyses that would need to be evaluated at the time such a SIP revision is submitted; these issues are not ripe for resolution in this action.

followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by March 1, 2024.

The EPA received no comments on the proposed option to modify allowance allocations under the Group 3 trading program for EGUs for the 2024 control period through a SIP revision and is finalizing the provisions as proposed.

2. SIP Option To Modify Allocations for 2025 and Beyond Under EGU Trading Program

For the 2025 control period and later, states in the CSAPR NO_X Ozone Season Group 3 Trading Program can modify the EPA-determined default allocations with an approved SIP revision. For the 2025 control period and later, SIPs can be full or abbreviated SIPs. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

In this final rule, the EPA is removing the previous regulatory text defining specific options for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines. These options for expanding trading program applicability through SIP revisions have been available to states since the start of the CSAPR trading programs for small EGUs and since the CSAPR Update for large non-EGU boilers and combustion turbines, and no state has chosen to use the SIP process for this purpose. Additionally, the EPA did not receive comment supporting these expansion options during the comment period for this rule. The EPA is finalizing a methodology for updating the affected EGU portion of the budget in this rule, and the regulatory text defining the applicability expansion to non-EGUs did not include a mechanism for updating the incremental non-EGU portion of a state's budget based on changes over time of the non-EGU fleet; therefore, continuation of the option to expand applicability to certain non-EGUs subject to the NO_X SIP Call would be inconsistent with the trading program as applied to EGUs in this rule.

However, the EPA recognizes that states may seek to include non-EGUs covered in this action in an emissions trading program, subject to important considerations to ensure equivalency in emissions reductions is maintained. While the EPA is not offering specific regulatory text to implement an option to expand the trading program applicability, a state could submit a SIP to expand the CSAPR NO_X Ozone Season Group 3 Trading Program applicability, which the EPA would evaluate on a case-by-case basis. The SIP revision would need to address critical program elements, and include: (1) high-quality baseline data, (2) ongoing Part 75 monitoring, and (3) provisions to update the non-EGU portion of the budget to appropriately reflect changes to the fleet over time.

For states that want to modify the EPA-determined default allocations, the EPA proposed that a state could submit a SIP revision that makes changes only to that provision while relying on the FIP for the remaining provisions of the EGU trading program. This abbreviated SIP option allows states to tailor the FIP to their individual choices while maintaining the FIP-based structure of the trading program. To ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace the EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

The SIP submittal deadline for this type of revision is December 1, 2023, if the state intends for the SIP revision to be effective beginning with the 2025 control period. For states that submit this type of SIP revision, the deadline to submit state-determined allocations beginning with the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024. Similarly, a state can submit a SIP revision beginning with the 2026 control period and beyond by December 1, 2024, with state allocations for the 2026 control period due June 1, 2025, and EPA recordation of the allocations by July 1, 2025.

The EPA received no comment on the option to replace certain allowance allocation provisions under the Group 3 trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

3. SIP Option To Replace the Federal EGU Trading Program With an Integrated State EGU Trading Program

For the 2025 control period and later, states in the CSAPR NO_X Ozone Season Group 3 Trading Program can choose to replace the Federal EGU trading program with an integrated State EGU trading program through an approved SIP revision. Under this option, a state can submit a SIP revision that makes changes only to modify the EPA-determined default allocations and that adopts identical provisions for the remaining portions of the EGU trading program. This SIP option allows states to replace these FIP provisions with state-based SIP provisions while continuing participation in the larger regional trading program. As with the abbreviated SIP option discussed previously, to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chooses to replace the EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside. Also, for the same reasons discussed with respect to the abbreviated SIP option, the EPA is removing the option for states to expand CSAPR NO_X Ozone Season Group 3 trading program applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, large non-EGU boilers and combustion turbines.

Deadlines for this type of SIP revision are the same as the deadlines for abbreviated SIP revisions. For the SIP-based program to start with the 2025 control period, the SIP deadline is December 1, 2023, the deadline to submit state-determined allocations for the 2025 control period under an approved SIP is June 1, 2024, and the deadline for the EPA to record those allocations is July 1, 2024, and so on.

The EPA received no comment on the option to replace the Federal trading program for EGUs with an integrated state trading program for EGUs for control periods in 2025 and later years through a SIP revision and is finalizing the provisions generally as proposed, with the exception that any potential expansion of trading program applicability under a SIP revision would be evaluated on a case-by-case basis.

4. SIP Revisions That Do Not Use the Trading Program

States can submit SIP revisions to replace the FIP that achieve the necessary EGU emissions reductions but do not use the CSAPR NO_X Ozone Season Group 3 Trading Program. For a transport SIP revision that does not use the CSAPR NO_X Ozone Season Group 3 Trading Program, the EPA would evaluate the transport SIP based on the particular control strategies selected and whether the strategies as a whole provide adequate and enforceable provisions ensuring that the necessary emissions reductions (*i.e.,* reductions equal to or greater than what the Group 3 trading program will achieve) will be achieved. To address the applicable CAA requirements, the SIP revision should include the following general elements: (1) a comprehensive baseline 2023 statewide NO_X emissions inventory (which includes existing control requirements), which should be consistent with the 2023 emissions inventory that the EPA used to calculate the required state budget in this final rule (unless the state can explain the discrepancy); (2) a list and description of control measures to satisfy the state emissions reduction obligation and a demonstration showing when each measure would be implemented to meet the 2023 and successive control periods; (3) fully-adopted state rules providing for such NO_X controls during the ozone season; (4) for EGUs greater than 25 MWe, monitoring and reporting under 40 CFR part 75, and for other units, monitoring and reporting procedures sufficient to demonstrate that sources are complying with the SIP (*see* 40 CFR part 51, subpart K (''source surveillance'' requirements)); and (5) a projected inventory demonstrating that state measures along with Federal measures will achieve the necessary emissions reductions in time to meet the 2023 and successive compliance deadlines (*e.g.,* enforceable reductions commensurate with installation of SCR on coal-fired EGUs by the 2027 ozone season). The SIPs must meet procedural requirements under the Act, such as the requirements for public hearing, be adopted by the appropriate state board or authority, and establish by a practically enforceable regulation or permit(s) a schedule and date for each affected source or source category to achieve compliance. Once the state has made a SIP submission, the EPA will evaluate the submission(s) for completeness before acting on the SIP. EPA's criteria for determining completeness of a SIP submission are codified at 40 CFR part 51, appendix V.

For further background information on considerations for replacing a FIP with a SIP, *see* the discussion in the final CSAPR rulemaking (76 FR 48326).

5. SIP Revision Requirements for Non-EGU or Industrial Source Control Requirements

EPA's promulgation of a non-EGU transport FIP would in no way affect the ability of states to submit, for review and approval, a SIP that replaces the requirements of the FIP with state requirements. To replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The state SIP submittal must demonstrate that the emissions reductions required by the SIP would continue to ensure that significant contribution from that state has been eliminated through permanent and enforceable measures. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP.

The most straightforward method for a state to submit a presumptively approvable SIP revision to replace the non-EGU portion of the FIPs for the state would be to provide a SIP that includes emissions limits at an equivalent or greater level of stringency than is specified for non-EGU sources meeting the applicability criteria and associated compliance assurance provisions for each of the unit types identified in section VI.C of this document.

Comment: One commenter stated that they believed EPA's assertion in the proposal that any SIP submittal would have to achieve equal or greater reductions for non-EGUs than the FIP was unlawful. The commenter asserted that a state's ability to replace the FIP must be tied to whether it has addressed the underlying nonattainment/maintenance concerns by reducing significant contribution from sources in the state below the significance threshold, (as opposed to whether it prohibits equivalent emissions to the FIP).

Response: The EPA recognizes that states may select emissions reductions strategies that differ from the emissions limitations included in the proposed non-EGU FIP; this is discussed in response to comments earlier in this section. For example, some states may desire to include non-EGUs in a trading program. This may be possible subject to taking into account a number of considerations as discussed earlier in this section to ensure equivalency between the different approaches. But the state must still demonstrate that the replacement SIP provides an equivalent or greater amount of emissions reductions as the proposed FIP to be presumptively approvable. The EPA anticipates that such emissions reductions strategies would have to achieve reductions equivalent to or beyond those emissions reductions already projected to occur in EPA's emissions projections and air quality modeling conducted at Steps 1 and 2. Such reductions must also be achieved by the 2026 ozone season.

EPA further acknowledges that a demonstration of equivalency using other control strategies is complicated by the fact that the final emissions limits for non-EGU sources are generally unit-specific and expressed in a variety of forms; comparative analysis with alternative control requirements to determine equivalency would need to take this into account. Similarly, we recognize that the emissions trading program for EGUs in this action includes a number of enhancements to ensure that the Step 3 determination of which emissions are ''significant'' and must be eliminated continues to be implemented over time. Although there is not a fixed, mass-based emissions budget established for each state in this action, there are other objective metrics that could guide states in developing replacement SIPs. For example, for non-EGUs, states may choose to conduct an analysis of their industrial stationary sources and present an alternative set of emissions limits applying to specific units that it believes would achieve an equivalent level of emissions reduction. States could apply cost-effectiveness thresholds for emissions control technologies that could be applied to establish that some alternative emissions control strategy results in equivalent or greater improvement at downwind receptors. The EPA anticipates that such a comparison may entail review of both baseline emissions information and growth projections between the different sets of units to ensure that a truly equivalent or greater degree of emissions reduction is achieved; additionality and emissions shifting potential may also need to be considered. We note that the CAMx policy case run for 2026 provides a benchmark for assessing the level of air quality improvement anticipated at receptors with implementation of the FIP. This data may be of use to states as part of a demonstration that a replacement SIP achieves an equivalent or greater level of air quality improvement to the FIP; however, the use of such modeling in such a demonstration would need to be more fully evaluated at the time of such a SIP revision.

In all cases, a SIP submitted by a state to replace the non-EGU components of the FIPs would very likely need to rely on permanent and practically enforceable controls measures that are included in the SIP and, once approved by the EPA, rendered federally enforceable. So-called ''demonstration-only'' or ''non-regulatory'' SIPs would very likely be insufficient; see discussion in response to comments earlier in this section. Further, the EPA anticipates that states would bear the burden of establishing that the state's alternative approach achieves at least an equivalent level of emissions reduction as the FIP.

E. Title V Permitting

This final rule, like CSAPR, the CSAPR Update, and the Revised CSAPR Update does not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing Title V, 40 CFR parts 70 and 71.[406] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emissions limitations and other conditions as necessary to ensure compliance with the applicable requirements of the CAA, including the requirements of the applicable SIP. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units subject to this final rule, most if not all of the sources at which the units are located are already subject to title V permitting requirements and already possess a title V operating permit. For sources subject to title V, the interstate transport requirements for the 2015 ozone NAAQS that are applicable to them under the FIPs finalized in this action would be ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, EGU requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the compliance assurance provisions, and liability, and for non-EGUs, the emissions limits and compliance requirements are, to the extent relevant to each source, ''applicable requirements'' that must be addressed in the permits.

Consistent with EPA's approach under CSAPR, the CSAPR Update and the Revised CSAPR Update, the applicable requirements resulting from the FIPs generally will have to be incorporated into affected sources' existing title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 71.7(f)), significant modifications (40 CFR 70.7(e)(4)) or the standard permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[407] For sources newly subject to title V that are affected sources under the FIPs, the initial title V permit issued pursuant to 40 CFR 70.7(a) should address the final FIP requirements.

As was the case in the CSAPR, the CSAPR Update and the Revised CSAPR Update, the new and amended FIPs impose no independent permitting requirements and the title V permitting process will impose no additional burden on sources already required to be permitted under title V.

1. Title V Permitting Considerations for EGUs

Title V of the CAA establishes the basic requirements for state title V permitting programs, including, among other things, provisions governing permit applications, permit content, and permit revisions that address applicable requirements under final FIPs in a manner that provides the flexibility necessary to implement market-based programs such as the trading programs established in CSAPR, the CSAPR Update, the Revised CSAPR Update and this final rule. 42 U.S.C. 7661a(b); 40 CFR 70.6(a)(8) & (10); 40 CFR 71.6(a)(8) & (10).

In CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA established standard requirements governing how sources covered by those rules would comply with title V and its regulations.[408] 40 CFR 97.506(d), 97.806(d) and 97.1006(d). For any new or existing sources subject to this rule, identical title V compliance provisions will apply with respect to the CSAPR NO_X Ozone Season Group 3 Trading Program. For example, the title V regulations provide that a permit issued under title V must include ''[a] provision stating that no permit revision shall be required under any approved . . . emissions trading and other similar programs or processes for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with these provisions in the title V regulations, in CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA included a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. 40 CFR 97.506(d)(1), 97.806(d)(1) and 97.1006(d)(1). This provision is also included in each title V permit for an affected source. This final rule maintains the approach taken under CSAPR, the CSAPR Update and the Revised CSAPR Update that allows allowances to be traded (or allocated, held, or deducted) without a revision to the title V permit of any of the sources involved.

Similarly, this final rule would also continue to support the means by which a source in the final trading program can use the title V minor modification procedure to change its approach for monitoring and reporting emissions, in certain circumstances. Specifically, sources may use the minor modification procedure so long as the new monitoring and reporting approach is one of the prior-approved approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update (*i.e.,* approaches using a continuous emissions monitoring system under subparts B and H of 40 CFR part 75, an excepted monitoring system under appendices D and E to 40 CFR part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of 40 CFR part 75), and the permit already includes a description of the new monitoring and reporting approach to be used. *See* 40 CFR 97.506(d)(2), 97.806(d)(2) and 97.1006(d)(2); 40 CFR 70.7(e)(2)(i)(B) and 71.7(e)(1)(i)(B). As described in EPA's 2015 Title V Guidance, sources may comply with this requirement by including a table of all of the approved monitoring and reporting approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update trading programs in which the source is required to participate, and the applicable requirements governing each of those approaches.[409] Inclusion of such a table in a source's title V permit therefore allows a covered unit that seeks to change or add to its chosen monitoring and recordkeeping approach to easily comply with the regulations

[406] Part 70 addresses requirements for state title V programs, and part 71 governs the Federal title V program.

[407] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to an affected source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(i) and 71.7(f)(1)(i).

[408] The EPA has also issued a guidance document and template that includes instructions for how to incorporate the applicable requirements into a source's Title V permit. *See* Memorandum dated May 13, 2015, from Anna Marie Wood, Director, Air Quality Policy Division, and Reid P. Harvey, Director, Clean Air Market Division, EPA, to Regional Air Division Directors, Subject: ''Title V Permit Guidance and Template for the Cross-State Air Pollution Rule'' (''2015 Title V Guidance''), available at *https://www.epa.gov/sites/default/files/2016–10/documents/csapr_title_v_permit_guidance.pdf.*

[409] *Id.*

governing the use of the title V minor modification procedure.

Under CSAPR, the CSAPR Update and the Revised CSAPR Update, to employ a monitoring or reporting approach different from the prior-approved approaches discussed previously, unit owners and operators must submit monitoring system certification applications to the EPA establishing the monitoring and reporting approach actually to be used by the unit, or, if the owners and operators choose to employ an alternative monitoring system, to submit petitions for that alternative to the EPA. These applications and petitions are subject to the EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are posted on EPA's website.[410] The EPA maintains the same approach for the trading program in this final rule.

2. Title V Permitting Considerations for Industrial Stationary Sources

For non-EGU sources, affected sources will need to work with their local, state, or tribal permitting authority to determine if the new applicable requirements should be incorporated into their existing title V permit under the reopening for cause, significant modification, or permit renewal procedures of the approved permitting program. Title V permits for existing sources will need to be updated to include the applicable requirements of this final rule and any necessary preconstruction permits obtained in order to comply with this final rule.

F. Relationship to Other Emissions Trading and Ozone Transport Programs

1. NO_X SIP Call

Sources in states affected by both the NO_X SIP Call for the 1979 ozone NAAQS and the requirements established in this final rule for the 2015 ozone NAAQS will be required to comply with the requirements of both rules. With respect to EGUs larger than 25 MW, in this rule the EPA is requiring NO_X ozone season emissions reductions from these sources in many of the NO_X SIP Call states, and at greater stringency than required by the NO_X SIP Call, by requiring the EGUs to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program. The emissions reductions required under this rule are therefore sufficient to satisfy the emissions reduction requirements under the NO_X SIP Call for these large EGUs.

With respect to the large non-EGU boilers and combustion turbines that formerly participated in the NO_X Budget Trading Program under the NO_X SIP Call, the EPA provided options under both the CSAPR Update and the Revised CSAPR Update for states to address these sources' ongoing NO_X SIP Call requirements by expanding applicability of the relevant CSAPR trading programs for ozone season NO_X emissions to include the sources, and no state chose to use these options. As discussed in sections VI.D.2 and VI.D.3, in this rule the EPA is removing the previous regulatory text defining specific options for states to expand trading program applicability to include these sources and instead will evaluate any SIP revisions seeking to include these sources in the Group 3 trading program on a case-by-case basis.[411]

2. Acid Rain Program

This rule does not affect any SO_2 and NO_X requirements under the Acid Rain Program, which are established separately under 40 CFR parts 72 through 78 and will continue to apply independently of this rule's provisions. Sources subject to the Acid Rain Program will continue to be required to comply with all requirements of that program, including the requirement to hold sufficient allowances issued under the Acid Rain Program to cover their SO_2 emissions after the end of each control period.

3. Other CSAPR Trading Programs

This rule does not substantively affect any provisions of the CSAPR NO_X Annual, CSAPR SO_2 Group 1, CSAPR SO_2 Group 2, CSAPR NO_X Ozone Season Group 1, or CSAPR NO_X Ozone Season Group 2 trading programs for sources that continue to participate in those programs. Sources subject to any of the CSAPR trading programs will continue to be required to comply with all requirements of all such trading programs to which they are subject, including the requirement to hold sufficient allowances issued under the respective programs to cover emissions after the end of each control period.

The EPA also notes that where a state's good neighbor obligations with respect to the 1997 ozone NAAQS or the 2008 ozone NAAQS have previously been met by participation of the state's large EGUs in the CSAPR NO_X Ozone Season Group 2 Trading Program (or earlier by the CSAPR NO_X Ozone Season Group 1 Trading Program), the EPA will deem those obligations to be satisfied by the participation of the same sources in the CSAPR NO_X Ozone Season Group 3 Trading Program. Specifically, for all states covered by the Group 3 trading program under this rule except Minnesota, Nevada, and Utah, participation of the state's EGUs in the Group 3 trading program will be deemed to satisfy not only the EGU-related portion of the state's good neighbor obligations with respect to the 2015 ozone NAAQS but also the state's good neighbor obligations with respect to the 2008 ozone NAAQS. In addition, for Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Wisconsin, participation of the state's EGUs in the Group 3 trading program will also be deemed to satisfy the state's good neighbor obligations with respect to the 1997 ozone NAAQS.[412]

VII. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with EPA's commitment to integrating environmental justice in the agency's actions, and following the directives set forth in multiple Executive orders, the Agency has analyzed the impacts of this final rule on communities with environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. Executive Order 12898 is discussed in section X.J of this final rule and analytical results are available in Chapter 7 of the *RIA.* This analysis is being provided for informational purposes only.

A. Introduction

Executive Order 12898 directs EPA to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples.[413] Additionally, Executive

[410] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

[411] Only one NO_X SIP Call state—Tennessee—continues to participate in the Group 2 trading program, and the EPA has already approved other SIP provisions addressing the ongoing NO_X SIP Call obligations for Tennessee's large non-EGU boilers and combustion turbines. *See* 84 FR 7998 (March 6, 2019); 86 FR 12092 (March 2, 2021).

[412] For the remaining state transitioning from the Group 2 trading program to the Group 3 trading program under this rule—Texas—as well as the remaining states that transitioned from the Group 2 trading program to the Group 3 trading program under the Revised CSAPR Update—Maryland, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—participation of the states' EGUs in the Group 2 trading program as required by the CSAPR Update was addressing good neighbor obligations of the states with respect to only the 2008 ozone NAAQS, not the 1997 ozone NAAQS. *See* 81 FR 74523–74526.

[413] 59 FR 7629, February 16, 1994.

Order 13985 is intended to advance racial equity and support underserved communities through Federal Government actions.[414] The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. The EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.'' [415] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, the EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

B. Analytical Considerations

The EPA's environmental justice (EJ) technical guidance [416] states that:

> The analysis of potential EJ concerns for regulatory actions should address three questions:
>
> 1. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
>
> 2. Are there potential EJ concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
>
> 3. For the regulatory option(s) under consideration, are potential EJ concerns created or mitigated compared to the baseline?

To address these questions in the EPA's first quantitative EJ analysis in the context of a transport rule, the EPA developed a unique analytical approach that considers the purpose and specifics of the final rulemaking, as well as the nature of known and potential exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential environmental justice characteristics (*e.g.,* residence of historically red lined areas), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated.

For the final rule, we employ two types of analytics to respond to the previous three questions: proximity analyses and exposure analyses. Both types of analyses can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[417] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, several caveats should be noted. For example, the air pollutant exposure metrics are limited to those used in the benefits assessment. For ozone, that is the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3) and for $PM_{2.5}$ that is the annual average. This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standard (NAAQS), whereas the $PM_{2.5}$ metric is more similar to the long term $PM_{2.5}$ standard. The air quality modeling estimates are also based on state level emissions data paired with facility-level baseline emissions, and provided at a resolution of 12km². Additionally, here we focus on air quality changes due to this final rulemaking and infer post-policy exposure burden impacts.

Exposure analytic results are provided in two formats: aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed information about ozone concentration changes experienced by everyone within each population.

In Chapter 7 of the *RIA* we utilize the two types of analytics to address the three EJ questions by quantitatively evaluating: (1) the proximity of affected facilities to potentially disadvantaged populations (section 7.3); and (2) the potential for disproportionate ozone and $PM_{2.5}$ concentrations in the baseline and concentration changes after rule implementation across different demographic groups (section 7.4). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local pollutants, such as NO_2 emitted from affected sources in this final rule. However, such analyses are less useful here as they do not account for the potential impacts of this final rule on long-range concentration changes. Baseline demographic proximity analysis presented in the *RIA* suggest that larger percentages of Hispanics, African Americans, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Relating these results to question 1 from section 7.2 of the *RIA,* we conclude that there may be potential EJ concerns associated with directly emitted pollutants that are affected by the regulatory action (*e.g.,* NO_2) for certain population groups of concern in the baseline. However, as proximity to affected facilities does not capture variation in baseline exposure across communities, nor does it indicate that any exposures or impacts will occur, these results do not in themselves demonstrate disproportionate impacts of affected facilities in the baseline and should not be interpreted as a direct measure of exposure or impact.

Whereas proximity analyses are limited to evaluating the representativeness of populations residing nearby affected facilities, the ozone and $PM_{2.5}$ exposure analyses can provide insight into all three EJ questions. Even though both the proximity and exposure analyses can potentially improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

The baseline analysis of ozone and $PM_{2.5}$ concentration burden responds to question 1 from EPA's environmental justice technical guidance document more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline ozone and $PM_{2.5}$ analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less

[414] 86 FR 7009, January 20, 2021.

[415] *https://www.epa.gov/environmentaljustice.*

[416] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

[417] The baseline for proximity analyses is current population information (*e.g.,* 2021), whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

educated, and children may experience somewhat higher ozone and $PM_{2.5}$ concentrations compared to the national average. Therefore, also in response to question 1, there likely are potential environmental justice concerns associated with ozone and $PM_{2.5}$ exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications. In addition, we infer that disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration due to similar modeled concentration reductions across population demographics (question 2).

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. Due to the very small differences observed in the distributional analyses of post-policy ozone and $PM_{2.5}$ exposure impacts across populations, we do not find evidence that potential EJ concerns related to ozone and $PM_{2.5}$ concentrations will be created or mitigated as compared to the baseline.[418]

C. Outreach and Engagement

Prior to proposal, the EPA hosted an outreach webinar with environmental justice stakeholders to share information about the proposed rule and solicit feedback about potential environmental justice considerations. The webinar was attended by representatives of state governments, federally recognized tribes, environmental NGOs, higher education institutions, industry, and the EPA.[419] Participants were invited to comment on pre-proposal environmental justice considerations during the webinar or submit written comments to a pre-proposal non-regulatory docket.

After proposal, the EPA opened a public comment period to invite the public to submit written comments to the regulatory docket for this rulemaking.[420] The EPA also invited the public to participate in a public hearing held on April 21, 2022. A transcript of the public hearing is available in the docket for this rulemaking. Additionally, on March 31, 2022, the EPA hosted an informational webinar with non-governmental groups and environmental justice stakeholders to answer questions and share information about the proposed rule. A record of this webinar, including the informational power point shared at the webinar is available in the docket for this rulemaking.

VIII. Costs, Benefits, and Other Impacts of the Final Rule

In the *RIA* for the Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards, the EPA estimated the health and climate benefits, compliance costs, and emissions changes that may result from the final rule for the analysis period 2023 to 2042. The estimated health and climate benefits and compliance costs are presented in detail in this *RIA.* The EPA notes that for EGUs the estimated benefits and compliance costs are directly associated with fully operating existing SCRs during ozone season; fully operating existing SNCRs during ozone season; installing state-of-the-art combustion controls; imposing a backstop emissions rate on certain units that lack SCR controls; and installing SCR and SNCR post-combustion controls. The EPA also notes that for non-EGUs the estimated health benefits and compliance costs are directly associated with installing controls to meet the NO_X emissions requirements presented in section I.B of this document.

For EGUs, the EPA analyzed this action's emissions budgets using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_X (2016$) in 2026. The EPA also analyzed a more and a less stringent alternative. The more and less stringent alternatives differ from the rule in that they set different NO_X ozone season emissions budgets for the affected EGUs and different dates for large, coal-fired EGUs' compliance with the backstop emissions rate.

For non-EGUs, the EPA developed an analytical framework to determine which industries and emissions unit types to include in a proposed Transport FIP for the 2015 ozone NAAQS transport obligations. A February 28, 2022 memorandum, titled "Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026," documents the analytical framework used to identify industries and emissions unit types included in the proposed FIP. To further evaluate the industries and emissions unit types identified and to establish the proposed emissions limits, the EPA reviewed Reasonably RACT rules, NSPS rules, NESHAP rules, existing technical studies, rules in approved SIP submittals, consent decrees, and permit limits. That evaluation is detailed in the Proposed Non-EGU Sectors TSD prepared for the proposed FIP. The EPA is retaining the industries and many of the emissions unit types included in the proposal in this final action. For the non-EGU industries, in the final rule we made some minor changes to the non-EGU emissions units covered, the applicability criteria, as well as provided for facility-wide emissions averaging for engines and for a low-use exemption to eliminate the need to install controls on low-use boilers.

Table VIII–1 provides the projected 2023 through 2027, 2030, 2035, and 2042 EGU NO_X, SO_2, $PM_{2.5}$, and CO_2 emissions reductions for the evaluated regulatory control alternatives. For additional information on emissions changes, see Table 4–6 and Table 4–7 in Chapter 4 of the *RIA.*

TABLE VIII–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042

	Final rule	Less stringent alternative	More stringent alternative
2023:			
NO_X (ozone season)	10,000	10,000	10,000
NO_X (annual)	15,000	15,000	15,000
SO_2 (annual)	1,000	3,000	1,000
CO_2 (annual, thousand metric tons)	....	....	....

[418] Please note, exposure results should not be extrapolated to other air pollutant. Detailed environmental justice analytical results can be found in Chapter 7 of the RIA.

[419] This does not constitute EPA's tribal consultation under E.O. 13175, which is described in section XI.F of this rule.

[420] Comments and responses regarding environmental justice considerations are available in Section 6 of the *RTC* document for this rulemaking.

TABLE VIII–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042—Continued

	Final rule	Less stringent alternative	More stringent alternative
$PM_{2.5}$ (annual)			
2024:			
NO_X (ozone season)	21,000	10,000	33,000
NO_X (annual)	25,000	15,000	57,000
SO_2 (annual)	19,000	5,000	59,000
CO_2 (annual, thousand metric tons)	10,000	4,000	20,000
$PM_{2.5}$ (annual)	1,000		1,000
2025:			
NO_X (ozone season)	32,000	10,000	56,000
NO_X (annual)	35,000	15,000	99,000
SO_2 (annual)	38,000	7,000	118,000
CO_2 (annual, thousand metric tons)	21,000	8,000	40,000
$PM_{2.5}$ (annual)	2,000	1,000	2,000
2026:			
NO_X (ozone season)	25,000	8,000	49,000
NO_X (annual)	29,000	12,000	88,000
SO_2 (annual)	29,000	5,000	104,000
CO_2 (annual, thousand metric tons)	16,000	6,000	34,000
$PM_{2.5}$ (annual)	1,000		2,000
2027:			
NO_X (ozone season)	19,000	6,000	43,000
NO_X (annual)	22,000	9,000	78,000
SO_2 (annual)	21,000	4,000	91,000
CO_2 (annual, thousand metric tons)	10,000	3,000	28,000
$PM_{2.5}$ (annual)	1,000		2,000
2030:			
NO_X (ozone season)	34,000	33,000	31,000
NO_X (annual)	62,000	59,000	50,000
SO_2 (annual)	93,000	98,000	51,000
CO_2 (annual, thousand metric tons)	26,000	23,000	8,000
$PM_{2.5}$ (annual)	1,000	1,000	
2035:			
NO_X (ozone season)	29,000	30,000	27,000
NO_X (annual)	46,000	46,000	41,000
SO_2 (annual)	21,000	19,000	15,000
CO_2 (annual, thousand metric tons)	16,000	15,000	8,000
$PM_{2.5}$ (annual)	1,000	1,000	
2042:			
NO_X (ozone season)	22,000	22,000	22,000
NO_X (annual)	23,000	22,000	21,000
SO_2 (annual)	15,000	15,000	7,000
CO_2 (annual, thousand metric tons)	9,000	8,000	4,000
$PM_{2.5}$ (annual).			

Emissions changes for NO_X, SO_2, and $PM_{2.5}$ are in tons.

Table VIII–2 provides a summary of the ozone season NO_X emissions for non-EGUs for the 20 states subject to the non-EGU emissions requirements starting in 2026, along with the estimated ozone season NO_X reductions for 2026 for the rule and the less and more stringent alternatives. The analysis in the *RIA* assumes that the estimated reductions in 2026 will be the same in later years.

TABLE VIII–2—OZONE SEASON NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES

State	2019 Ozone season emissions [a]	Final rule—ozone season NO_X reductions	Less stringent—ozone season NO_X reductions	More stringent—ozone season NO_X reductions
AR	8,790	1,546	457	1,690
CA	16,562	1,600	1,432	4,346
IL	15,821	2,311	751	2,991
IN	16,673	1,976	1,352	3,428
KY	10,134	2,665	583	3,120
LA	40,954	7,142	1,869	7,687
MD	2,818	157	147	1,145
MI	20,576	2,985	760	5,087
MO	11,237	2,065	579	4,716
MS	9,763	2,499	507	2,650

TABLE VIII–2—OZONE SEASON NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES—Continued

State	2019 Ozone season emissions [a]	Final rule—ozone season NO_X reductions	Less stringent—ozone season NO_X reductions	More stringent—ozone season NO_X reductions
NJ	2,078	242	242	258
NV [421]	2,544	0	0	0
NY	5,363	958	726	1,447
OH	18,000	3,105	1,031	4,006
OK	26,786	4,388	1,376	5,276
PA	14,919	2,184	1,656	4,550
TX	61,099	4,691	1,880	9,963
UT	4,232	252	52	615
VA	7,757	2,200	978	2,652
WV	6,318	1,649	408	2,100
Totals	302,425	44,616	16,786	67,728

[a] The 2019 ozone season emissions are calculated as 5/12 of the annual emissions from the following two emissions inventory files: nonegu_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0 and oilgas_SmokeFlatFile_2019NEI_POINT_20210721_controlupdate_13sep2021_v0.

For EGUs, the EPA analyzed ozone season NO_X emissions reductions and the associated costs to the power sector using the Integrated Planning Model (IPM) and its underlying data and inputs. For non-EGUs, the EPA prepared an assessment summarized in the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* and the memorandum includes estimated emissions reductions by state for the rule.[421]

Table VIII–3 reflects the estimates of the changes in the cost of supplying electricity for the regulatory control alternatives for EGUs and estimates of complying with the emissions requirements for non-EGUs. The costs presented in Table VIII–3 do not include monitoring and reporting costs, which EPA summarizes in section X.B.2 of this document. The monitoring and reporting costs presented in section X.B.2 are $0.35 million per year for EGUs and $3.8 million per year for non-EGUs. For EGUs, compliance costs are negative in 2026. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period. As such the model may undertake a compliance pathway that pushes higher costs later into the forecast period, since future costs are discounted more heavily than near term costs. This can result in a policy scenario showing single year costs that are lower than the Baseline, but over the entire forecast horizon, the policy scenario shows higher costs.[422] For a detailed description of these cost trends, please see Chapter 4, section 4.5.2, of the *RIA.* For a detailed description of the methods and results from the memorandum titled *Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, Assumed Control Technologies for Meeting the Final Emissions Limits, and Estimated Emissions Units, Emissions Reductions, and Costs,* see Chapter 4, sections 4.4 and 4.5.4 of the *RIA.*

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042

	Final rule	Less-stringent alternative	More-stringent alternative
2023:			
EGUs	57	56	49
Non-EGUs			
Total	57	56	49
2024:			
EGUs	(5)	(35)	840
Non-EGUs			
Total	(5)	(35)	840
2025:			
EGUs	(5)	(35)	840
Non-EGUs			
Total	(5)	(35)	840
2026:			

[421] We are not aware of existing non-EGU emissions units in Nevada that meet the applicability criteria for non-EGUs in the final rule. If any such units in fact exist, they would be subject to the requirements of the rule just as in any other state. In addition, any new emissions unit in Nevada that meets the applicability criteria in the final rule will be subject to the final rule's requirements. See section III.B.1.d.

[422] As a sensitivity, the EPA re-calculated costs assuming annual costs cannot be negative. This resulted in annualized 2023–42 costs under the final rule increasing from $448.6 million to $449.5 million (less than 1%) and did not change the conclusions of the RIA. See Section 4.5.2 of the RIA for more information.

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042—Continued

	Final rule	Less-stringent alternative	More-stringent alternative
EGUs	(5)	(35)	840
Non-EGUs	570	140	1,300
Total	570	110	2,100
2027:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2028:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2029:			
EGUs	24	(47)	760
Non-EGUs	570	140	1,300
Total	600	97	2,000
2030:			
EGUs	710	770	840
Non-EGUs	570	140	1,300
Total	1,300	920	2,100
2031:			
EGUs	710	770	840
Non-EGUs	570	140	1,300
Total	1,300	920	2,100
2032:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2033:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2034:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2035:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2036:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2037:			
EGUs	820	850	590
Non-EGUs	570	140	1,300
Total	1,400	990	1,900
2038:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2039:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2040:			
EGUs	820	830	600

TABLE VIII–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042—Continued

	Final rule	Less-stringent alternative	More-stringent alternative
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2041:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900
2042:			
EGUs	820	830	600
Non-EGUs	570	140	1,300
Total	1,400	970	1,900

Tables VIII–4 and VIII–5 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95 percent confidence interval. In each of these tables, for each discount rate and regulatory control alternative, two benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates. For additional information on these benefits, see Chapter 5 of the *RIA.*

TABLE VIII–4—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE-RELATED PREMATURE MORTALITY AND ILLNESS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES IN 2023

[95 Percent confidence interval; millions of 2016$] [a] [b]

Disc rate	Pollutant	Final rule	Less stringent alternative	More stringent alternative
3%	Ozone Benefits	$100 [$27 to $220] [c] *and* $820 [$91 to $2,100] [d].	$100 [$27 to $220] [c] *and* $810 [$91 to $2,100] [d].	$110 [$28 to $230] [c] *and* $840 [$94 to $2,200] [d].
7%	Ozone Benefits	$93 [$17 to 210] [c] *and* $730 [$75 to $1,900] [d].	$93 [$17 to $210] [c] *and* $730 [$75 to $1,900] [d].	$96 [$18 to $210] [c] *and* $750 [$77 to $2,000] [d].

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NO_X for the ozone season. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the final standards would apply to these sources.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

TABLE VIII–5—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-RELATED PREMATURE MORTALITY AND ILLNESS FOR THE FINAL RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES IN 2026

[95% Confidence interval; millions of 2016$] [a] [b]

Disc rate	Pollutant	Final rule	Less stringent alternative	More stringent alternative
3%	Ozone Benefits	$1,100 [$280 to $2,400] [c] *and* $9,400 [$1,000 to $25,000] [d].	$420 [$110 to $900] [c] *and* $3,400 [$380 to $8,900] [d].	$1,900 [470 to $4,000] [c] *and* $15,000 [$1,700 to $40,000] [d].
	PM Benefits	$2,000 [$220 to $5,300] *and* $4,400 [$430 to $12,000].	$530 [$57 to $1,400] *and* $1,100 [$110 to $3,100].	$6,400 [$690 to $17,000] *and* $14,000 [$1,300 to $37,000]
	Ozone plus PM Benefits.	$3,200 [$500 to $7,700] [c] *and* $14,000 [$1,500 to $36,000] [d].	$950 [$160 to $2,300] [c] *and* $4,600 [$490 to $12,000] [d].	$8,300 [$1,200 to $21,000] [c] *and* $29,000 [$3,000 to $77,000] [d].
7%	Ozone Benefits	$1,000 [$180 to $2,300] [c] *and* $8,400 [$850 to $22,000] [d].	$380 [$68 to $850] [c] *and* $3,100 [$310 to $8,100] [d].	$1,700 [$300 to $3,800] [c] *and* $14,000 [$1,400 to $36,000] [d].
	PM Benefits	$1,800 [$190 to $4,700] *and* $3,900 [$380 to $11,000].	470 [$50 to $1,200] *and* $1,000 [$100 to $2,800].	$5,800 [$600 to $15,000] *and* $12,000 [$1,200 to $33,000].
	Ozone plus PM Benefits.	$2,800 [$370 to $7,000] [c] *and* $12,000 [$1,200 to $33,000] [d].	$850 [$120 to $2,100] [c] *and* $4,100 [$410 to $11,000] [d].	$7,500 [$910 to $19,000] [c] *and* $26,000 [$2,600 to $69,000] [d].

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NO_X for the ozone season and annual changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

In Tables VIII–6, VIII–7, and VIII–8, the EPA presents a summary of the monetized health and climate benefits, costs, and net benefits of the rule and the more and less stringent alternatives for 2023, 2026, and 2030, respectively. There are important water quality benefits and health benefits associated with reductions in concentrations of air pollutants other than ozone and $PM_{2.5}$ that are not quantified. Discussion of the non-monetized health, welfare, and water quality benefits is found in Chapter 5 of the *RIA.* In this action, monetized climate benefits are presented for purposes of providing a complete economic impact analysis under E.O. 12866 and other relevant Executive orders. The estimates of GHG emissions changes and the monetized benefits associated with those changes is not part of the record basis for this action, which is taken to implement the good neighbor provision, CAA section 110(a)(2)(D)(i)(I), for the 2015 ozone NAAQS.

TABLE VIII–6—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2023 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a] [b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$100 and $820	$100 and $810	$110 and $840.
Climate Benefits	$5	$4	$5.
Total Benefits	$100 and $820	$100 and $820	$110 and $840.
Costs [d]	$57	$56	$49.
Net Benefits	$48 and $760	$48 and $760	$66 and $800.

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

TABLE VIII–7—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2026 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a] [b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$3,200 and $14,000	$950 and $4,600	$8,300 and $29,000.
Climate Benefits	$1,100	$420	$2,100.
Total Benefits	$4,300 and $15,000	$1,400 and $5,000	$10,000 and $31,000.
Costs [d]	$570	$110	$2,100.
Net Benefits	$3,700 and $14,000	$1,300 and $4,900	$8,300 and $29,000.

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

TABLE VIII–8—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2030 FOR THE U.S.

[3% Discount rate for benefits, millions of 2016$] [a] [b]

	Final rule	Less stringent alternative	More stringent alternative
Health Benefits [c]	$3,400 and $15,000	$1,000 and $4,900	$9,000 and $31,000.
Climate Benefits	$1,500	$1,300	$500.
Total Benefits	$4,900 and $16,000	$2,300 and $6,200	$9,500 and $31,000.
Costs [d]	$1,300	$920	$2,100.
Net Benefits	$3,600 and $15,000	$1,400 and $5,300	$7,400 and $29,000.

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.
[c] The health benefits are associated with two point estimates from two different epidemiologic studies. For the purposes of presenting the values in this table the health and climate benefits are discounted at 3 percent.
[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. For EGUs, an NPV of costs was calculated using a 3.76 percent real discount rate consistent with the rate used in IPM's objective function for cost-minimization. For further information on the discount rate use, please see Chapter 4, Table 4–8 in the RIA.

In addition, Table VIII–9 presents estimates of the present value (PV) of the monetized benefits and costs and the equivalent annualized value (EAV), an estimate of the annualized value of the net benefits consistent with the present value, over the twenty-year period of 2023 to 2042. The estimates of the PV and EAV are calculated using discount rates of 3 and 7 percent as recommended by OMB's Circular A–4 and are presented in 2016 dollars discounted to 2023.

TABLE VIII–9—MONETIZED ESTIMATED HEALTH AND CLIMATE BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE FINAL RULE AND LESS AND MORE STRINGENT ALTERNATIVES, 2023 THROUGH 2042

[Millions 2016$, discounted to 2023]

	3 Percent discount rate		7 Percent discount rate	
	PV	EAV	PV	EAV
Health benefits				
Final Rule	$200,000	$13,000	$130,000	$12,000
Less Stringent Alternative	67,000	4,500	40,000	3,800
More Stringent Alternative	410,000	28,000	240,000	23,000
Climate Benefits [a]				
Final Rule	15,000	970	15,000	970
Less Stringent Alternative	11,000	770	11,000	770
More Stringent Alternative	14,000	920	14,000	920
Compliance Costs				
Final Rule	14,000	910	9,400	770
Less Stringent Alternative	8,700	590	5,300	500
More Stringent Alternative	25,000	1,700	17,000	1,600
Net Benefits				
Final Rule	200,000	13,000	140,000	12,000
Less Stringent Alternative	70,000	4,700	42,000	4,000
More Stringent Alternative	400,000	27,000	240,000	22,000

[a] Climate benefits are calculated using four different estimates of the social cost of carbon (SC–CO_2) (model average at 2.5 percent, 3 percent, and 5 percent discount rates; 95th percentile at 3 percent discount rate). For presentational purposes in this table, the climate benefits associated with the average SC–CO_2 at a 3-percent discount rate are used in the columns displaying results of other costs and benefits that are discounted at either a 3-percent or 7-percent discount rate.

As shown in Table VIII–9, the PV of the monetized health benefits of this rule, discounted at a 3-percent discount rate, is estimated to be about $200 billion ($200,000 million), with an EAV of about $13 billion ($13,000 million). At a 7-percent discount rate, the PV of the monetized health benefits is estimated to be $130 billion ($130,000 million), with an EAV of about $12 billion ($12,000 million). The PV of the monetized climate benefits of this rule, discounted at a 3-percent discount rate, is estimated to be about $15 billion ($15,000 million), with an EAV of about $970 million. The PV of the monetized compliance costs, discounted at a 3-percent rate, is estimated to be about $14 billion ($14,000 million), with an EAV of about $910 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $9.4 billion ($9,400 million), with an EAV of about $770 million.

In addition to the analysis of costs and benefits as described above, for the final rule, the EPA was able to conduct a full-scale photochemical grid modeling run of the effects of the ''final rule'' emissions control scenario in 2026. This modeling can be used to estimate the impacts on projected 2026 ozone design values that are expected from the combined EGU and non-EGU control emissions reductions in this final rule. These results do not replace the AQAT-generated estimates used for our Step 3 determinations, and the EPA needed to continue to use AQAT for Step 3 determinations in order to characterize various potential control scenarios to inform these regulatory determinations. Nonetheless, though they differ slightly from the AQAT-generated air quality estimates of the final rule control scenario conducted for purposes of our Step 3 analysis (as presented in section V.D of this document), these results using full-scale photochemical grid modeling complement those estimates and confirm in all cases the regulatory conclusions reached applying AQAT.[423] Appendix 3A of the *RIA* presents the full results of the projected impacts of the final rule control scenario on ozone levels using CAMx. To briefly summarize, the largest reductions in ozone design values at identified receptors are predicted to occur in the Houston-Galveston-Brazoria, Texas area. In this area the reductions from the final rule case range from 0.7 to 0.9 ppb. At most of the receptors in both the Dallas/Ft Worth and the New York/Coastal Connecticut areas the reductions in ozone range from 0.4 to 0.5 ppb. At receptors in Indiana, Michigan, and Wisconsin near the shoreline of Lake Michigan, ozone is projected to decline by 0.3 to 0.4 ppb, but by as much as 0.5 ppb at the receptor in Muskegon, MI. Reductions of 0.1 ppb are predicted in the urban and near-urban receptors in Chicago. In the West, ozone reductions just under 0.2 ppb are predicted at receptors in Denver with slightly greater reductions, just above 0.2 ppb, at receptors in Salt Lake City. At receptors in Phoenix, California, El Paso/Las Cruces, and southeast New Mexico the reductions in ozone are predicted to be less than 0.1 ppb.

[423] Note that the EPA's ''overcontrol'' analysis relies primarily on a ''Step 3'' control scenario rather than the ''full geography'' scenario. The CAMx modeling described here captures the effects of the rule as a whole and so is more akin to the ''full geography'' scenario, which the EPA does not believe is the appropriate method for conducting overcontrol analysis. Nonetheless, as explained in the Ozone Transport Policy Analysis Final Rule TSD, the results under either scenario establish no overcontrol, and the CAMx results presented here do not call those conclusions into question.

IX. Summary of Changes to the Regulatory Text for the Federal Implementation Plans and Trading Programs for EGUs

This section describes the amendments to the regulatory text that implement the findings and remedy discussed elsewhere in this rule with respect to EGUs. The primary CFR amendments are revisions to the FIP provisions addressing states' good neighbor obligations related to ozone in 40 CFR part 52 as well as the revisions to the regulations for the CSAPR NO_X Ozone Season Group 3 Trading Program in 40 CFR part 97, subpart GGGGG. In conjunction with the amendments to the Group 3 trading program, the monitoring, recordkeeping, and reporting regulations in 40 CFR part 75 are being amended to reflect the addition of certain new reporting requirements associated with the amended trading program and the administrative appeal provisions in 40 CFR part 78 are being amended to identify certain additional types of appealable decisions of the EPA Administrator under the amended trading program. The provisions to address the transition of the EGUs in certain states from the Group 2 trading program to the Group 3 trading program are implemented in part through revisions to the regulations noted previously and in part through revisions to the regulations for the Group 2 trading program in 40 CFR part 97, subpart EEEEE.

In addition to these primary amendments, certain revisions are being made to the regulations for the other CSAPR trading programs in 40 CFR part 97, subparts AAAAA through EEEEE, for conformity with the amended provisions of the Group 3 trading program, as discussed in section VI.B.13. Documents have been included in the docket for this rule showing all of the revisions in redline-strikeout format.

A. Amendments to FIP Provisions in 40 CFR Part 52

The CSAPR, CSAPR Update, and Revised CSAPR Update FIP requirements related to ozone season NO_X emissions are set forth in 40 CFR 52.38(b) as well as other sections of part 52 specific to each covered state. The existing text of § 52.38(b)(1) identifies the trading program regulations in 40 CFR part 97, subparts BBBBB, EEEEE, and GGGGG, as constituting the relevant FIP provisions relating to seasonal NO_X emissions and transported ozone pollution. Because in this rulemaking the EPA is establishing new or amended FIP requirements not only for the types of EGUs covered by the trading programs but also for certain types of industrial sources, an amendment to § 52.38(b)(1) clarifies that the trading programs constitute the FIP provisions only for the sources meeting the applicability requirements of the trading programs. A parallel clarification is being added to §§ 52.38(a)(1) and 52.39(a) with respect to the CSAPR FIP requirements relating to annual NO_X emissions, SO_2 emissions, and transported fine particulate pollution.

The states whose EGU sources are required to participate in the CSAPR NO_X Ozone Season Group 1, Group 2, and Group 3 trading programs under the FIPs established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, as well as the control periods for which those requirements apply, are identified in § 52.38(b)(2). The amendments to this paragraph expand the applicability of the Group 3 trading program to sources in the ten additional states that the EPA is adding to the Group 3 trading program starting with the 2023 control period and end the applicability of the Group 2 trading program (with the exception of certain provisions) for sources in seven of the ten states after the 2022 control period, as discussed in section VI.B.2.[424] The paragraphs within § 52.38(b)(2) are being renumbered to clarify the organization of the provisions and to facilitate cross-references from other regulatory provisions. Regarding the two states currently participating in the Group 2 trading program through approved SIP revisions that replaced the previous FIPs issued under the CSAPR Update (Alabama and Missouri), a provision indicating that the EPA will no longer administer the state trading programs adopted under those SIP revisions after the 2022 control period is being added at § 52.38(b)(16)(ii)(B).

In the Revised CSAPR Update, the EPA established several options for states to revise their SIPs to modify or replace the FIPs applicable to their sources while continuing to use the Group 3 trading program as the mechanism for meeting the states' good neighbor obligations. As in effect before this rule, § 52.38(b)(10), (11), and (12) established options to replace allowance allocations for the 2022 control period, to adopt an abbreviated SIP revision for control periods in 2023 or later years, and to adopt a full SIP revision for control periods in 2023 or later years, respectively.[425] As discussed in section VI.D, the EPA is retaining these SIP revision options and is making them available for all states covered by the Group 3 trading program after the geographic expansion. The option under § 52.38(b)(10) to replace allowance allocations for a single control period is being amended to be available for the 2024 control period, with attendant revisions to the years and dates shown in § 52.38(b)(10) (multiple paragraphs) and (b)(17)(i) as well as the Group 3 trading program regulations, as discussed in section IX.B. The options under § 52.38(b)(11) and (12) to adopt abbreviated or full SIP revisions are being amended to be available starting with the 2025 control period, with attendant revisions to § 52.38(b)(11)(iii), (b)(12)(iii), and (b)(17)(ii).[426] The removal of the previous options for states to expand applicability of the trading programs for ozone season NO_X emissions to certain non-EGUs and smaller EGUs, discussed in sections VI.D.2 and VI.D.3, is accomplished by the removal or revision of multiple paragraphs of § 52.38(b), including most notably the removal of § 52.38(b)(4)(i), (b)(5)(i), (b)(8)(i)–(ii), (b)(9)(i)–(ii), (b)(11)(i)–(iii), and (b)(12)(i)–(iii).

The changes with respect to set-asides and the treatment of units in Indian country discussed in section VI.B.9, although implemented largely through amendments to the Group 3 trading program regulations, are also implemented in part through amendments to § 52.38(b)(11) and (12). First, the text in § 52.38(b)(11)(iii)(A) and (b)(12)(iii)(A) identifying the portion of each state trading budget for which a state may establish state-determined allowance allocations is being revised to exclude any allowances in a new unit set-aside or Indian country existing unit set-aside. Second, the text in § 52.38(b)(12)(vi) identifying provisions that states may not adopt into their SIPs (because the provisions concern regulation of sources in Indian country not subject to a state's CAA implementation planning authority) are being revised to include the provisions of the amended Group 3 trading program addressing allocation and recordation of allowances from all types of set-asides. Finally, the text in § 52.38(b)(12)(vii) authorizing the EPA to modify the previous approval of a SIP revision with regard to the assurance provisions ''if and when a covered unit is located in Indian country'' are being revised to account for the fact that at least one covered unit is already located in Indian country not subject to a state's CAA planning authority.

The transitional provisions discussed in sections VI.B.12.b and VI.B.12.c to

[424] Like the previous text of § 52.38(b)(2), the final amended text expressly encompasses sources in Indian country within the respective states' borders.

[425] Revisions to the deadlines for states with approved SIP revisions to submit their state-determined allowance allocations to the EPA for subsequent recordation were finalized in an earlier final rule in this docket. See 87 FR 52473 (August 26, 2022).

[426] No state currently in the Group 3 trading program has submitted a SIP revision to make use of these options in control periods before the control periods in which the options can be used under the amended provisions.

convert certain 2017–2022 Group 2 allowances to Group 3 allowances and to recall certain 2023–2024 Group 2 allowances, although promulgated as amendments to the Group 2 trading program regulations, will necessarily be implemented after the end of the 2022 control period. Amendments clarifying that these provisions continue to apply to the relevant sources and holders of allowances notwithstanding the transition of certain states out of the Group 2 trading program after the 2022 control period are being added at § 52.38(b)(14)(iii). Cross-references clarifying that the EPA's allocations of the converted Group 3 allowances are not subject to modification through SIP revisions are also being added to the existing provisions at § 52.38(b)(11)(iii)(D) and (b)(12)(iii)(D).

The general FIP provisions applicable to all states covered by this rule as set forth in § 52.38(b)(2) are being replicated in the state-specific subparts of 40 CFR part 52 for each of the ten states that the EPA is adding to the Group 3 trading program.[427] In each such state-specific CFR subpart, provisions are being added indicating that sources in the state are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with respect to emissions starting in 2023. Provisions are also being added repeating the substance of § 52.38(b)(13)(i), which generally provides that the Administrator's full and unconditional approval of a full SIP revision correcting the same SIP deficiency that is the basis for a FIP promulgated in this rulemaking would cause the FIP to no longer apply to sources subject to the state's CAA implementation planning authority, and § 52.38(b)(14)(ii), which generally provides the EPA with authority to complete recordation of EPA-determined allowance allocations for any control period for which EPA has already started such recordation notwithstanding the approval of a state's SIP revision establishing state-determined allowance allocations.

For each of the seven states that the EPA is removing from the Group 2 trading program, the provisions of the state-specific CFR subparts indicating that sources in the state are required to participate in that trading program are being revised to end that requirement with respect to emissions after 2022, and a further provision is being added repeating the substance of § 52.38(b)(14)(iii), which identifies certain provisions that continue to apply to sources and allowances notwithstanding discontinuation of a trading program with respect to a particular state.[428] In addition, for the five states that during their time in the Group 2 trading program have not exercised the option to adopt full SIP revisions to replace the FIPs issued under the CSAPR Update (all but Alabama and Missouri), obsolete provisions concerning the unexercised SIP revision option are being removed.

No amendments with respect to FIP requirements for EGUs are being made to the state-specific CFR subparts for the twelve states whose sources currently participate in the Group 3 trading program[429] except as needed to update cross-references or to implement the changes related to the treatment of Indian country, as discussed in section IX.D.

B. Amendments to Group 3 Trading Program and Related Regulations

To implement the geographic expansion of the Group 3 trading program and the revised trading budgets that are being established under the new and amended FIPs in this rulemaking, several sections of the Group 3 trading program regulations are being amended. Revisions identifying the applicable control periods, deadlines for certification of monitoring systems, and deadlines for commencement of quarterly reporting for sources not previously covered by the Group 3 trading program are being made at §§ 97.1006(c)(3)(i), 97.1030(b)(1), and 97.1034(d)(2)(i), respectively. Revisions identifying the new or revised budgets and new unit set-asides for the control periods after 2022 for all covered states are being made at § 97.1010(a)(1) and (c)(2), respectively.

Each of the enhancements to the Group 3 trading program discussed in section VI.B is also implemented primarily through revisions to the trading program regulations. The dynamic budget-setting process discussed in sections VI.B.1.b.i and VI.B.4 is implemented at § 97.1010(a)(2) through (4), and the associated revised process for determining variability limits and assurance levels discussed in section VI.B.5 is implemented at § 97.1010(e). The Group 3 allowance bank recalibration process discussed in sections VI.B.1.b.ii and VI.B.6 is implemented at § 97.1026(d). The backstop daily NO_X emissions rate component of the primary emissions limitation discussed in sections VI.B.1.c.i and VI.B.7 is implemented at §§ 97.1006(c)(1)(i) and 97.1024(b)(1) and (3), accompanied by the addition of a definition of ''backstop daily NO_X emissions rate'' and modification of the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'' in §§ 97.1002 and 97.1006(c)(6). The secondary emissions limitation for sources found responsible for exceedances of the assurance levels discussed in sections VI.B.1.c.ii and VI.B.8 is implemented at §§ 97.1006(c)(1)(iii) and (iv) and (c)(3)(ii) and 97.1025(c), accompanied by the addition of a definition of ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'' in § 97.1002.

The changes relating to set-asides, the treatment of Indian country, and unit-level allowance allocations discussed in section VI.B.9 of this document are implemented through revisions to multiple paragraphs of §§ 97.1010, 97.1011, and 97.1012, as well as limited revisions to §§ 97.1002 (definition of ''allocate or allocation'') and 97.1006(b)(2). In § 97.1010, paragraphs (b), (c), and (d) address the amounts for each control period of the Indian country existing unit set-asides, new unit set-asides, and Indian country new unit set-asides, respectively.[430] Paragraphs (b) and (d) reflect the establishment of Indian country existing unit set-asides starting with the 2023 control period and the discontinuation of Indian country new unit set-asides after the 2022 control period.

A newly added definition at § 97.1002 for ''coal-derived fuel'' (based on the existing definition in 40 CFR 72.2) helps in implementation of both the backstop daily NO_X emissions rate provisions and the unit-level allocation provisions by clarifying that the provisions apply without regard to how any coal combusted by a unit might have been processed before combustion. Another newly added definition at § 97.1002 for ''historical control period'' helps in implementation of the dynamic budget-setting provisions, the secondary emissions limitation provisions, and the

[427] *See* §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1240(d) (Minnesota), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1492 (Nevada), 52.1930(a) (Oklahoma), 52.2283(d) (Texas), 52.2356 (Utah), and 52.2587(e) (Wisconsin).

[428] *See* §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1930(a) (Oklahoma), 52.2283(d) (Texas), and 52.2587(e) (Wisconsin).

[429] *See* §§ 52.731(b) (Illinois), 52.789(b) (Indiana), 52.940(b) (Kentucky), 52.984(d) (Louisiana), 52.1084(b) (Maryland), 52.1186(e) (Michigan), 52.1584(e) (New Jersey), 52.1684(b) (New York), 52.1882(b) (Ohio), 52.2040(b) (Pennsylvania), 52.2440(b) (Virginia), and 52.2540(b) (West Virginia).

[430] The former § 97.1011(c), which addresses the relationships of set-asides and variability limits to state trading budgets, is being relocated to § 97.1011(f).

unit-level allocation provisions by facilitating references to data reported by a unit for periods before the unit's entry into the Group 3 trading program.

The revisions to § 97.1011 refocus the section exclusively on allocation to ''existing'' units from the portion of each state emissions budget not reserved in a new unit set-aside or Indian country new unit set-aside. In § 97.1011(a), the provision formerly in § 97.1011(a)(1) requiring allocations to existing units to be made in the amounts provided in NODAs issued by the EPA is being split into two separate provisions, with paragraph (a)(1) applying to existing units in the state and areas of Indian country covered by the state's CAA implementation planning authority and paragraph (a)(2) applying to existing units in areas of Indian country not covered by the state's CAA implementation planning authority.[431] This split will facilitate the submission and approval of SIP revisions by states interested in submitting state-determined allowance allocations for the units over which they exercise CAA implementation authority, while leaving allocations to any units outside their authority to be addressed either by the EPA or by the relevant tribe under an approved tribal implementation plan. The process for determining default allocations to existing units of allowances from state trading budgets starting with the 2026 control period is set forth in revised § 97.1011(b), while the former provisions of § 97.1011(b), which concern timing and notice procedures for allocations to new units, are being relocated to § 97.1012. The provisions addressing incorrectly allocated allowances at § 97.1011(c) are being streamlined by relocating the portions applicable to new units to § 97.1012(c). In addition, as discussed in section VI.B.9.d, § 97.1011(c)(5) is being revised to provide that, starting with the 2024 control period, any incorrectly allocated allowances recovered after May 1 of the year following the control period will not be reallocated to other units in the state but instead would be transferred to a surrender account.

The revisions to § 97.1012 retain the section's current focus on allocations to ''new'' units, generally combining the former provisions at § 97.1012 with the former provisions at § 97.1011(b) and (c) that address new units. The text of multiple paragraphs in both § 97.1012(a) and (b) is being revised as needed to reflect the change in treatment of Indian country discussed in section VI.B.9.a, under which the new unit set-asides will be used to provide allowance allocations to new units both in non-Indian country and Indian country within the borders of the respective states for control periods starting in 2023.[432] The timing and notice provisions in § 97.1012(a)(13) and (b)(13) are relocated from former § 97.1011(b)(1) and (2). The text of § 97.1012(c), addressing incorrect allocations to new units, is largely relocated from § 97.1011(c) (which addresses incorrect allocations to existing units) and reflects a parallel revision addressing the disposition of recovered allowances, as discussed in section VI.B.9.d.

The amendments to § 97.1021 implement two distinct sets of changes discussed in sections VI.B.9 and VI.D.1. First, revisions to § 97.1021(b) through (e) replace the previous schedule for recording Group 3 allowances for the 2023 and 2024 control periods established in the August 2022 Recordation Rule with an updated recordation schedule tailored to the effective date of this rule. The updated schedule also eliminates the unused former option for states to provide state-determined allowance allocations for the 2022 control period and establishes a substantively equivalent new option for states to provide state-determined allowance allocations for the 2024 control period. Second, revisions to § 97.1021(g) through (j) begin recordation for Indian country existing unit set-asides starting with allocations for the 2023 control period, modify the text to eliminate references to state-determined allocations of allowances from new unit set-asides, and end recordation for Indian country new unit set-asides after allocations for the 2022 control period.

Implementation of the revisions to the Group 3 trading program is also accomplished in part through amendments to regulations in other CFR parts. In 40 CFR part 75, which contains detailed monitoring, recordkeeping, and reporting requirements applicable to sources covered by the Group 3 trading program, the additional recordkeeping and reporting requirements discussed in section VI.B.10 of this document are implemented through the addition of §§ 75.72(f) and 75.73(f)(1)(ix) and (x) and revisions to § 75.75, and the procedures for calculating daily total heat input and daily total NO_X emissions and the procedures for apportioning NO_X mass emissions monitored at a common stack among the individual units using the common stack are being added at sections 5.3.3, 8.4(c), and 8.5.3 of appendix F to part 75. In 40 CFR part 78, which contains the administrative appeal procedures applicable to decisions of the EPA Administrator under the Group 3 trading program, § 78.1(b)(19) is being amended to add calculation of the dynamic budgets to the list of administrative decisions under the trading program regulations that will be appealable under those procedures.

C. Transitional Provisions

As discussed in section VI.B.12, the EPA is establishing several transitional provisions for sources entering the Group 3 trading program. The provisions discussed in section VI.B.12.a of this document, concerning the prorating of state emissions budgets, assurance levels, and unit-level allocations for the 2023 control period, are implemented through the Group 3 trading program regulations. Specifically, the state emissions budgets for the 2023 control period will be prorated according to procedures set out at § 97.1010(a)(1)(ii). Variability limits for the 2023 control period, and the resulting assurance levels, will be computed under § 97.1010(e) from the prorated state emissions budgets. Unit-level allocations to existing units for the 2023 control period will be computed from the prorated state emissions budgets according to procedures substantively the same as the procedures codified in § 97.1011(b) for calculating default allocations to existing units for later control periods, as discussed in section VI.B.9.b, and will be announced in the notice of data availability issued under § 97.1011(a)(1) and (2) for the 2023 through 2025 control periods.

The remaining transitional provisions are being implemented through the Group 2 trading program regulations.

[431] An additional provision currently in § 97.1011(a)(1), which clarifies that an allocation or lack of allocation to a unit in a NODA does not constitute a determination by the EPA that the unit is or is not a CSAPR NO_X Ozone Season Group 3 unit, is being relocated to § 97.1011(a)(3). The former § 97.1011(a)(2), which provides for certain existing units that cease operations to receive allocations for their first five control periods of non-operation and provides for the allowances for subsequent control periods to be allocated to the relevant state's new unit set-asides, is inconsistent with the proposed revisions to the set-asides and the default allowance allocation process, as discussed in section VI.B.9, and is being removed as obsolete.

[432] Revisions are also being made to the text of § 97.1012(a) and (b) for the control periods in 2021 and 2022 consistent with the revisions to the parallel provisions in the regulations for the other CSAPR trading programs, generally calling for allocations to units in areas of Indian country subject to a state's CAA implementation planning authority to be made from the new unit set-asides instead of from the Indian country new unit set-asides.

The creation of an additional Group 3 allowance bank for the 2023 control period through the conversion of banked 2017–2022 Group 2 allowances as discussed in section VI.B.12.b of this document is implemented at § 97.826(e).[433] Related provisions addressing the use of Group 3 allowances to satisfy after-arising compliance obligations under the Group 2 trading program or the Group 1 trading program are implemented at §§ 97.826(f)(2) and 97.526(e)(3), respectively, and related provisions addressing recordation of late-arising allocations of Group 1 allowances are implemented at § 97.526(d)(2)(iii). The recall of Group 2 allowances previously issued for the 2023 and 2024 control periods as discussed in section VI.B.12.c of this document is implemented at § 97.811(e).

Decisions of the Administrator related to the allowance bank creation provisions and the allowance recall provisions are identified as appealable decisions under 40 CFR part 78 through revisions to § 78.1(b)(17)(viii) and (ix).

D. Clarifications and Conforming Revisions

As discussed in section VI.B.13 of this document, the EPA is revising the provisions regarding allowance allocations for units in Indian country in all the CSAPR trading programs so that instead of distinguishing among units based on whether they are or are not located in Indian country, the revised provisions distinguish among units based on whether they are or are not covered by a state's CAA implementation planning authority. The revisions are implemented in multiple paragraphs of §§ 97.411(b), 97.412, 97.511(b), 97.512, 97.611(b), 97.612, 97.711(b), 97.712, 97.811(b), and 97.812. The associated revisions to states' options regarding SIP revisions to establish state-determined allowance allocations for units covered by their CAA implementation planning authority are implemented in multiple paragraphs of §§ 52.38(a) and (b) and 52.39 as well as the state-specific subparts of 40 CFR part 52.

Certain other revisions to the regulatory text in the FIP and trading program regulations are minor simplifications and clarifications. First, in the Group 2 trading program regulations, the paragraphs in § 97.810 setting forth the amounts of state emissions budgets, new unit set-asides, Indian country new unit set-asides, and variability limits for states that the EPA is transitioning out of the Group 2 trading program are being modified to indicate that the amounts are applicable under that program only for control periods through 2022.

Second, as noted in sections VI.D.2 and VI.D.3, the existing options for states subject to the NO_X SIP Call to expand applicability of the Group 2 trading program to include certain non-EGUs and smaller EGUs are being eliminated. While the most directly affected provisions are the provisions setting forth the SIP options at § 52.38(b)(4), (5), (8), (9), (12), and (13), as discussed in section IX.A of this document, the changes also render references to ''base'' units and ''base'' sources in the regulations for the Group 2 trading program and the Group 3 trading program obsolete. Removal of the references to ''base'' units and ''base'' sources affects multiple paragraphs of §§ 97.802, 97.806, 97.825, 97.1002, 97.1006, and 97.1025.

Third, to clarify the regulatory text, the EPA is removing the language in the Group 3 trading program regulations that formerly appeared at §§ 97.1002 (definition of ''common designated representative's assurance level''), 97.1006(c)(2)(iii), 97.1010(d), and 97.1011(a)(1) referencing supplemental amounts of allowances issued for the 2021 control period and associated increments to the 2021 assurance levels (each state's assurance level increment was described as 21 percent of the state's supplemental amount of allowances). In place of the removed language, the EPA is restating the amounts of the 2021 state emissions budgets in § 97.1010(a)(1)(i) so as to include the supplemental amounts of allowances and is restating the amounts of the 2021 variability limits in § 97.1010(e)(1) so as to include the associated assurance level increments. The revised language is substantively equivalent to and simpler than the previous language.

Fourth, in 40 CFR part 75, the EPA is removing obsolete text in § 75.73(c) and (f) to clarify the context for other text being added to the section, as discussed in section IX.B of this document.

Fifth, in 40 CFR part 52, the EPA is adding §§ 52.38(a)(7)(iii) and 52.39(k)(3) to clarify in §§ 52.38 and 52.39 that the Allowance Management System housekeeping provisions added by the Revised CSAPR Update at §§ 97.426(c), 97.626(c), and 97.726(c) in the regulations for the CSAPR NO_X Annual, SO_2 Group 1, and SO_2 Group 2 trading programs, respectively, continue to apply after the sources in a given state have been removed from the programs, consistent with the text of the latter provisions.

Finally, the EPA is updating cross-references throughout 40 CFR parts 52 and 97 for consistency with the other amendments being made in this rulemaking.

X. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive orders (''E.O.'') can be found at *https://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is a significant regulatory action within the scope of section 3(f)(1) of Executive Order 12866 that was submitted to the Office of Management and Budget (OMB) for review. Any changes made in response to Executive Order 12866 review have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis, which is contained in the ''Regulatory Impact Analysis for Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452–R–23–001], is available in the docket and is briefly summarized in section VIII of this document.

B. Paperwork Reduction Act (PRA)

1. Information Collection Request for Electric Generating Units

The information collection activities in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2709.01. The EPA has placed a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The EPA is finalizing an information collection request (ICR), related specifically to electric generating units (EGU), for the Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards. The rule would amend the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 trading program addressing seasonal NO_X emissions in various states. Under the amendments, all EGU sources in the original twelve Group 3 states (Illinois, Indiana,

[433] The provision formerly at § 97.826(e)(1) is being relocated to § 97.826(f)(1), and the provision formerly at § 97.826(e)(2) is being removed as no longer necessary.

Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) would remain. Additionally, EGU sources in seven states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin) currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 ozone season. Further, sources in three states not currently covered by any CSAPR NO_X ozone season trading program would join the revised Group 3 trading program: Minnesota, Nevada, and Utah. In total, EGU sources in 22 states would now be covered by the Group 3 program.

There is an existing ICR (OMB Control Number 2060–0667), that includes information collection requirements placed on EGU sources for the six Cross-State Air Pollution Rule (CSAPR) trading programs addressing sulfur dioxide (SO_2) emissions, annual nitrogen oxides (NO_X) emissions, or seasonal NO_X emissions in various sets of states, and the Texas SO_2 trading program which is modeled after CSAPR. This ICR accounts for the additional respondent burden related to the amendments to the CSAPR NO_X Ozone Group 3 trading program.

The principal information collection requirements under the CSAPR and Texas trading programs relate to the monitoring and reporting of emissions and associated data in accordance with 40 CFR part 75. Other information collection requirements under the programs concern the submittal of information necessary to allocate and transfer emissions allowances and the submittal of certificates of representation and other typically one-time registration forms.

Affected sources under the CSAPR and Texas trading programs are generally stationary, fossil fuel-fired boilers and combustion turbines serving generators larger than 25 megawatts (MW) producing electricity for sale. Most of these affected sources are also subject to the Acid Rain Program (ARP). The information collection requirements under the CSAPR and Texas trading programs and the ARP substantially overlap and are fully integrated. The burden and costs of overlapping requirements are accounted for in the ARP ICR (OMB Control Number 2060–0258). Thus, this ICR accounts for information collection burden and costs under the CSAPR NO_X Ozone Season Group 3 trading program that are incremental to the burden and costs already accounted for in both the ARP and CSAPR ICRs.

For most sources already reporting data under the CSAPR NO_X Ozone Season Group 3 or the CSAPR NO_X Ozone Group 2 trading programs, the reporting requirements will remain identical so there will be no incremental burden or cost. Certain sources currently reporting data will be subject to additional emissions reporting requirements under the rule requiring these sources to make a one-time monitoring plan and DAHS update. These sources include those with a common stack configuration and/or those that are large, coal-fired EGUs. Additionally, sources with a common stack configuration have the option to install additional monitoring equipment to measure emissions at each individual unit within the facility, and for purposes of estimating information collection costs and burden, the EPA assumes certain sources will utilize this option. Finally, the assessment of incremental cost and burden are required for those sources in the three states not currently reporting data under a CSAPR NO_X Ozone Season program. Sources in Minnesota are already reporting data for the CSAPR NO_X Annual program with almost identical information collection requirements, requiring only a one-time monitoring plan and DAHS update. Most of the affected sources in Nevada and Utah are already reporting data as part of the Acid Rain Program, thus only requiring a monitoring plan and DAHS update as well. There are a small number of sources in Nevada and Utah that do not report emissions data to the EPA under 40 CFR part 75 and will need to implement a Part 75 monitoring methodology which includes burdens related to installation, certification, and necessary updates.

Respondents/affected entities: Industry respondents are stationary, fossil fuel-fired boilers and combustion turbines serving electricity generators subject to the CSAPR and Texas trading programs, as well as non-source entities voluntarily participating in allowance trading activities. Potential state respondents are states that can elect to submit state-determined allowance allocations for sources located in their states.

Respondent's obligation to respond: Industry respondents: voluntary and mandatory (sections 110(a) and 301(a) of the Clean Air Act).

Estimated number of respondents: The EPA estimates that there would be 120 industry respondents.

Frequency of response: on occasion, quarterly, and annually.

Total estimated additional burden: 2,289 hours (per year). Burden is defined at 5 CFR 1320.03(b).

Total estimated additional cost: $356,623 (per year); includes $182,379 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

2. Information Collection Request for Non-Electric Generating Units

The information collection activities in this final rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2705.02. The EPA has filed a copy of the non-EGU ICR in the docket for this rule, and it is briefly summarized here.

ICR No. 2705.02 is a new request and it addresses the burden associated with new regulatory requirements under the final rule. Owners and operators of certain non-Electric Generating Unit (non-EGU) industry stationary sources will potentially modify or install new emissions controls and associated monitoring systems to meet the nitrogen oxides (NO_X) emissions limits of this final rule. The burden in this ICR reflects the new monitoring, calibrating, recordkeeping, reporting and testing activities required of covered industrial sources. This information is being collected to assure compliance with the final rule. In accordance with the Clean Air Act Amendments of 1990, any monitoring information to be submitted by sources is a matter of public record. Information received and identified by owners or operators as confidential business information (CBI) and approved as CBI by the EPA, in accordance with 40 CFR chapter I, part 2, subpart B, shall be maintained appropriately (see 40 CFR part 2; 41 FR 36902, September 1, 1976; amended by 43 FR 39999, September 8, 1978; 43 FR 42251, September 28, 1978; 44 FR 17674, March 23, 1979).

Respondents/affected entities: The respondents/affected entities are the owners/operators of certain non-EGU industry sources in the following industry sectors: furnaces in Glass and Glass Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; kilns in Cement and Cement Product Manufacturing; reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; and boilers in Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills; and combustors and incinerators in Solid Waste Combustors and Incinerators.

Respondent's obligation to respond: Voluntary and mandatory. (Sections 110(a) and 301(a) of the Clean Air Act.) All data that is recorded or reported by respondents is required by the final rule, titled ''Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards.''

Estimated number of respondents: 3,328.

Frequency of response: The specific frequency for each information collection activity within the non-EGU ICR is shown at the end of the ICR document in Tables 1 through 18. In general, the frequency varies across the monitoring, recordkeeping, and reporting activities. Some recordkeeping such as work plan preparation is a one-time activity whereas pipeline engine maintenance recordkeeping is conducted quarterly. Reporting frequency is on an annual basis.

Total estimated burden: 11,481 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $3,823,000 (average per year); includes $2,400,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. When OMB approves this ICR, the Agency will announce that approval in the **Federal Register** and publish a technical amendment to 40 CFR part 9 to display the OMB control number for the approved information collection activities contained in this final rule.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses, which includes EGUs and non-EGUs and are described in more detail below. In 2026, the EPA identified a total of 29 small entities affected by the rule. Of these, 2 small entities may experience costs of greater than 1 percent of revenues. In 2026 for EGUs, the EPA identified 19 small entities. The EPA's decision to exclude units smaller than 25 MW capacity from the final rule, and exclusion of uncontrolled units smaller than 100 MW from backstop emissions rates significantly reduced the burden on small entities by reducing the number of affected small entity-owned units. Further, in 2026 for non-EGUs, there are ten small entities, and two small entities are estimated to have a cost-to-sales impact between 1.7 and 2.4 percent of their revenues.

The Agency has not determined that a significant number of small entities potentially affected by the rule will have compliance costs greater than 1 percent of annual revenues during the compliance period. The EPA has concluded that there will be no significant economic impact on a substantial number of small entities (No SISNOSE) for this rule overall. Details of this analysis are presented in Chapter 6 of the *RIA,* which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This action contains no unfunded Federal mandate for State, local, or Tribal governments as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any State, local, or Tribal government. This action contains a Federal mandate under UMRA, 2 U.S.C. 1531–1538, that may result in expenditures of $100 million or more in any one year for the private sector. Accordingly, the costs and benefits associated with this action are discussed in section VIII of this preamble and in the *RIA,* which is in the docket for this rule. Additional details are presented in the *RIA.* This action is not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This final action has tribal implications. However, it would neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

The EPA is finalizing a finding that interstate transport of ozone precursor emissions from 23 upwind states (Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states. The EPA is promulgating FIP requirements to eliminate interstate transport of ozone precursors from these 23 states. Under CAA section 301(d)(4), the EPA is extending FIP requirements to apply in Indian country located within the upwind geography of the final rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction. The EPA's determinations in this regard are described further in section III.C.2 of this document, *Application of Rule in Indian Country and Necessary or Appropriate Finding.* The EPA finds that all covered existing and new EGU and non-EGU sources that are located in the ''301(d) FIP'' areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. To the EPA's knowledge, only one covered existing EGU or non-EGU source is located within the 301(d) FIP areas: the Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah. This final action has tribal implication because of the extension of FIP requirements into Indian country and because, in general, tribes have a vested interest in how this final rule would affect air quality.

The EPA hosted an environmental justice webinar on October 26, 2021, that was attended by state regulatory authorities, environmental groups, federally recognized tribes, and small business stakeholders. The EPA issued tribal consultation letters addressed to 574 tribes in February 2022 after the proposed rule was signed. The EPA received no further requests to facilitate additional tribal consultation for the final rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it implements a previously promulgated health-based Federal standard. This action's health and risk assessments are contained in Chapter 5 and 6 of the *RIA.* The EPA believes that the ozone-related benefits, $PM_{2.5}$-related benefits, and CO_2- related benefits from this final rule will further improve children's health. Additionally, the ozone and $PM_{2.5}$ EJ exposure analyses in Chapter 7 of the *RIA* suggests that nationally, children (ages 0–17) will experience at least as great a reduction in ozone and $PM_{2.5}$ exposures as adults (ages 18–64) in 2023 and 2026 under all regulatory alternatives of this rulemaking.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The EPA has prepared a Statement of Energy Effects for the final regulatory control alternative as follows. The Agency estimates a 1 percent change in retail electricity prices on average across the contiguous U.S. in the 2025 run year, a 4 percent reduction (28 GWh) in coal-fired electricity generation, a 2 percent increase (21 GWh) in natural gas-fired electricity generation, and a 1 percent increase (8 GWh) in renewable electricity generation as a result of this final rule. The EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2025. Details of the estimated energy effects are presented in Chapter 4 of the *RIA,* which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or indigenous peoples) and low-income populations.

The EPA believes that the human health or environmental conditions that exist prior to this action result in or have the potential to result in disproportionate and adverse human health or environmental effects on people of color, low-income populations and/or Indigenous peoples. The documentation for this decision is contained in section VII of this document, *Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement,* and in Chapter 7, *Environmental Justice Impacts* of the *RIA,* which is in the public document. Briefly, proximity demographic analyses found larger percentages of Hispanics, African Americans, people below the poverty level, people with less educational attainment, and people linguistically isolated are living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of African Americans, people below the poverty level, and with less educational attainment living within 5 km and 10 km of an affected non-EGU facility. Considering the known limitations of proximity analyses, including the inability to assess policy-specific impacts, we also performed analysis of baseline EJ ozone and $PM_{2.5}$ exposures. Baseline ozone and $PM_{2.5}$ exposure analyses show that certain populations, such as Hispanics, Asians, those linguistically isolated, those less educated, and children may experience disproportionately higher ozone and $PM_{2.5}$ exposures as compared to the national average. American Indians may also experience disproportionately higher ozone concentrations than the reference group.

The EPA believes that this action is not likely to change existing disproportionate and adverse effects on people of color, low-income populations and/or Indigenous peoples. Specifically, we do not find evidence that potential EJ concerns related to ozone or $PM_{2.5}$ exposures will be meaningfully exacerbated or mitigated in the regulatory alternatives under consideration as compared to the baseline. We infer that baseline disparities in the ozone and $PM_{2.5}$ concentration burdens are likely to persist after implementation of the regulatory action or alternatives under consideration, due to similar modeled concentration reductions across population demographics. Importantly, the action described in this rule is expected to lower ozone and $PM_{2.5}$ in many areas, including in ozone nonattainment areas, and thus mitigate some pre-existing health risks across all populations evaluated.

The EPA additionally identified and addressed environmental justice concerns by providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action through outreach activities conducted by the Agency. The information supporting this Executive order review is contained in section VII of this document.

K. Congressional Review Act

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. Because this action falls within the definition provided by 5 U.S.C. 804(2), the rule's effective date is consistent with 5 U.S.C. 801(a)(3).

L. Determinations Under CAA Section 307(b)(1) and (d)

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the D.C. Circuit: (i) when the agency action consists of ''nationally applicable regulations promulgated, or final actions taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, but ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.'' For locally or regionally applicable final actions, the CAA reserves to the EPA complete discretion whether to invoke the exception in (ii).[434]

[434] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C.

Continued

This rulemaking is ''nationally applicable'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is applying a uniform legal interpretation and common, nationwide analytical methods with respect to the requirements of CAA section 110(a)(2)(D)(i)(I) concerning interstate transport of pollution (*i.e.,* ''good neighbor'' requirements) to promulgate FIPs that satisfy these requirements for the 2015 ozone NAAQS. Based on these analyses, the EPA is promulgating FIPs for 23 states located across a wide geographic area in eight of the ten EPA regions and ten Federal judicial circuits. Given that this action addresses implementation of the good neighbor requirements of CAA section 110(a)(2)(D)(i)(I) in a large number of states located across the country, and given the interdependent nature of interstate pollution transport and the common core of knowledge and analysis involved in promulgating these FIPs, this is a ''nationally applicable'' action within the meaning of CAA section 307(b)(1).

In the alternative, to the extent a court finds this action to be locally or regionally applicable, the Administrator is exercising the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of ''nationwide scope or effect'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is interpreting and applying section 110(a)(2)(d)(i)(I) of the CAA for the 2015 ozone NAAQS based on a common core of nationwide policy judgments and technical analysis concerning the interstate transport of pollutants throughout the continental U.S. In particular, the EPA is applying here the same, nationally consistent 4-step framework for assessing good neighbor obligations for the 2015 ozone NAAQS that it has applied in other nationally applicable rulemakings, such as CSAPR, the CSAPR Update, and the Revised CSAPR Update. The EPA is relying on the results from nationwide photochemical grid modeling using a 2016 base year and 2023 projection year as the primary basis for its assessment of air quality conditions and pollution contribution levels at Step 1 and Step 2 of that 4-step framework and applying a nationally uniform approach to the identification of nonattainment and maintenance receptors across the entire geographic area covered by this final rule.[435]

The Administrator finds that this is a matter on which national uniformity in judicial resolution of any petitions for review is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the basic law under the Act. The Administrator also finds that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results for different states, and that a nationally consistent approach to the CAA's mandate concerning interstate transport of ozone pollution constitutes the best use of agency resources. The EPA's responses to comments on the appropriate venue for petitions for review are contained in section 1.10 of the *RTC* document.

For these reasons, this final action is nationally applicable or, alternatively, the Administrator is exercising the complete discretion afforded to him by the CAA and finds that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1) and is publishing that finding in the **Federal Register**. Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by August 4, 2023.

This action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, ''the promulgation or revision of an implementation plan by the Administrator under [CAA section 110(c)].'' 42 U.S.C. 7407(d)(1)(B). This action, among other things, promulgates new Federal implementation plans pursuant to the authority of section 110(c). To the extent any portion of this final action is not expressly identified under section 307(d)(1)(B), the Administrator determines that the provisions of section 307(d) apply to such final action. *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').

Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

[435] In the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that the ''nationwide scope or effect'' exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. *See* H.R. Rep. No. 95–294 at 323, 324, reprinted in 1977 U.S.C.C.A.N. 1402–03.

List of Subjects

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 75

Environmental protection, Administrative practice and procedure, Air pollution control, Continuous emissions monitoring, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Michael S. Regan,

Administrator.

For the reasons stated in the preamble, parts 52, 75, 78, and 97 of title 40 of the Code of Federal Regulations are amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 52.38 by:

■ a. In paragraph (a)(1), removing ''(NO_X), except'' and adding in its place ''(NO_X) for sources meeting the applicability criteria set forth in subpart AAAAA, except'';

■ b. In paragraph (a)(3) introductory text:

■ i. Removing ''(a)(2)(i) or (ii)'' and adding in its place ''(a)(2)''; and

■ ii. Removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';

■ c. In paragraph (a)(3)(i), removing ''State and'' and adding in its place

''State and areas of Indian country within the borders of the State subject to the State's SIP authority and that'';
■ d. In paragraph (a)(4) introductory text, removing ''for the State's sources, and'' and adding in its place ''with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and'';
■ e. Revising table 1 to paragraph (a)(4)(i)(B);
■ f. In paragraph (a)(4)(ii), removing ''deadlines for submission of allocations or auction results under paragraphs (a)(4)(i)(B) and (C)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (a)(4)(i)(B)'';
■ g. In paragraph (a)(5) introductory text, removing ''State (but not sources in any Indian country within the borders of the State), regulations'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations'';
■ h. Revising table 2 to paragraph (a)(5)(i)(B);
■ i. In paragraph (a)(5)(iv), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ j. In paragraph (a)(5)(v), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';
■ k. In paragraph (a)(5)(vi), removing ''deadlines for submission of allocations or auction results under paragraphs (a)(5)(i)(B) and (C)'' and adding in its place ''deadline for submission of allocations or auction results under paragraph (a)(5)(i)(B)'';
■ l. Revising paragraphs (a)(6) and (a)(7)(ii);
■ m. Adding paragraph (a)(7)(iii);
■ n. In paragraphs (a)(8)(i) and (ii), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ o. In paragraph (a)(8)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';
■ p. In paragraph (b)(1), removing ''year), except'' and adding in its place ''year) for sources meeting the applicability criteria set forth in subparts BBBBB, EEEEE, and GGGGG, except'';
■ q. Redesignating paragraphs (b)(2)(i) and (ii) as paragraphs (b)(2)(i)(A) and (B), respectively, paragraphs (b)(2)(iii) and (iv) as paragraphs (b)(2)(ii)(A) and (B), respectively, and paragraph (b)(2)(v) as paragraph (b)(2)(iii)(A);
■ r. In newly redesignated paragraph (b)(2)(ii)(A), removing ''Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.'' and adding in its place ''Iowa, Kansas, and Tennessee.'';
■ s. Adding paragraphs (b)(2)(ii)(C) and (b)(2)(iii)(B) and (C);
■ t. In paragraph (b)(3) introductory text:
■ i. Removing ''or (ii)''; and
■ ii. Removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ u. In paragraph (b)(3)(i), removing ''State and'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority and that'';
■ v. Revising paragraph (b)(4) introductory text;
■ w. Removing and reserving paragraph (b)(4)(i);
■ x. Revising table 3 to paragraph (b)(4)(ii)(B) and paragraphs (b)(4)(iii) and (b)(5) introductory text;
■ y. Removing and reserving paragraph (b)(5)(i);
■ z. Revising table 4 to paragraph (b)(5)(ii)(B);
■ aa. In paragraph (b)(5)(v), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ bb. In paragraph (b)(5)(vi), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';
■ cc. Revising paragraphs (b)(5)(vii), (b)(7) introductory text, (b)(7)(i), and (b)(8) introductory text;
■ dd. Removing and reserving paragraphs (b)(8)(i) and (ii);
■ ee. Revising paragraph (b)(8)(iii)(A), table 5 to paragraph (b)(8)(iii)(B), and paragraphs (b)(8)(iv) and (b)(9) introductory text;
■ ff. Removing and reserving paragraphs (b)(9)(i) and (ii);
■ gg. Revising paragraph (b)(9)(iii)(A) and table 6 to paragraph (b)(9)(iii)(B);
■ hh. In paragraph (b)(9)(vi), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ ii. Revising paragraphs (b)(9)(vii) and (viii), (b)(10) introductory text, (b)(10)(i) and (ii), (b)(10)(v)(A) and (B), and (b)(11) introductory text;
■ jj. Removing and reserving paragraphs (b)(11)(i) and (ii);
■ kk. In paragraph (b)(11)(iii) introductory text, removing ''§§ 97.1011(a) and (b)(1) and 97.1012(a)'' and adding in its place ''§ 97.1011(a)(1)'';
■ ll. Revising paragraph (b)(11)(iii)(A);
mm. In paragraph (b)(11)(iii)(B):
■ i. Removing ''§ 97.1011(a)'' and adding in its place ''§ 97.1011(a)(1)''; and
■ ii. Adding ''and'' after the semicolon;
■ nn. Removing and reserving paragraph (b)(11)(iii)(C);
■ oo. Revising paragraphs (b)(11)(iii)(D), (b)(11)(iv), and (b)(12) introductory text;
■ pp. Removing and reserving paragraphs (b)(12)(i) and (ii);
■ qq. In paragraph (b)(12)(iii) introductory text, removing ''§§ 97.1011(a) and (b)(1) and 97.1012(a)'' and adding in its place ''§ 97.1011(a)(1)'';
■ rr. Revising paragraph (b)(12)(iii)(A);
■ ss. In paragraph (b)(12)(iii)(B):
■ i. Removing ''§ 97.1011(a)'' and adding in its place ''§ 97.1011(a)(1)''; and
■ ii. Adding ''and'' after the semicolon;
■ tt. Removing and reserving paragraph (b)(12)(iii)(C);
■ uu. Revising paragraphs (b)(12)(iii)(D), (b)(12)(vi) through (viii), (b)(13) introductory text, and (b)(13)(i);
■ vv. In paragraph (b)(13)(ii), removing ''regulations, including any sources made subject to such regulations pursuant to paragraph (b)(9)(ii) or (b)(12)(ii) of this section, the'' and adding in its place ''regulations the'';
■ ww. In paragraph (b)(14)(i)(F), removing ''§ 97.825(b)'' and adding in its place ''§§ 97.806(c)(2) and (3) and 97.825(b)'';
■ xx. In paragraph (b)(14)(i)(G), removing ''§ 97.826(e)'' and adding in its place ''§ 97.826(f)'';
■ yy. Revising paragraphs (b)(14)(ii) and (iii);
■ zz. In paragraph (b)(15)(i), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ aaa. Revising paragraph (b)(15)(ii);
■ bbb. In paragraph (b)(15)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';

■ ccc. In paragraph (b)(16)(i)(A), removing ''the State and'' and adding in its place ''sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for'';
■ ddd. Revising paragraphs (b)(16)(i)(B) and (C);
■ eee. Redesignating paragraph (b)(16)(ii) as paragraph (b)(16)(ii)(A), and, in newly redesignated paragraph (b)(16)(ii)(A), removing ''(b)(2)(iv)'' and adding in its place ''(b)(2)(ii)(B)'';
■ fff. Adding paragraph (b)(16)(ii)(B); and
■ ggg. Revising paragraphs (b)(17)(i) through (iii).

The revisions and additions read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of nitrogen oxides?

(a) * * *

(4) * * *

(i) * * *

(B) * * *

TABLE 1 TO PARAGRAPH (a)(4)(i)(B)

Year of the control period for which CSAPR NO_X Annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(5) * * *

(i) * * *

(B) * * *

TABLE 2 TO PARAGRAPH (a)(5)(i)(B)

Year of the control period for which CSAPR NO_X Annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(6) *Withdrawal of CSAPR FIP provisions relating to NO_X annual emissions.* Except as provided in paragraph (a)(7) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1), (a)(2)(i), and (a)(3) and (4) of this section for sources in the State and Indian country within the borders of the State subject to the State's SIP authority, the provisions of paragraph (a)(2)(i) of this section will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(7) * * *

(ii) Notwithstanding the provisions of paragraph (a)(6) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart AAAAA authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(iii) Notwithstanding any discontinuation pursuant to paragraph (a)(2)(ii) or (a)(6) of this section of the applicability of subpart AAAAA of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR NO_X Annual allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(A) The provisions of § 97.426(c) of this chapter (concerning the transfer of CSAPR NO_X Annual allowances between certain Allowance Management System accounts under common control).

(B) [Reserved]

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(C) The provisions of subpart EEEEE of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2017 through 2022 only, except as provided in paragraph (b)(14)(iii) of this section: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.

(iii) * * *

(B) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2023 and each subsequent year: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Texas, and Wisconsin.

(C) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring on and after August 4, 2023, and in each subsequent year: Minnesota, Nevada, and Utah.

* * * * *

(4) *Abbreviated SIP revisions replacing certain provisions of the Federal CSAPR NO_X Ozone Season Group 1 Trading Program.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart BBBBB of part 97 of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and not substantively replacing any other provisions, as follows:

* * * * *

(ii) * * *

(B) * * *

TABLE 3 TO PARAGRAPH (b)(4)(ii)(B)

Year of the control period for which CSAPR NO_X Ozone Season Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(iii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(4)(ii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(4)(ii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(4)(ii) of this section.

(5) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 1 Trading Programs.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 1 Trading Program set forth in §§ 97.502 through 97.535 of this chapter, except that the SIP revision:

* * * * *

(ii) * * *

(B) * * *

TABLE 4 TO PARAGRAPH (b)(5)(ii)(B)

Year of the control period for which CSAPR NO_X Ozone Season group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(5)(ii) through (v) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(5)(ii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(5)(ii) of this section.

* * * * *

(7) *State-determined allocations of CSAPR NO_X Ozone Season Group 2 allowances for 2018.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 2 allowance allocation provisions replacing the provisions in § 97.811(a) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2018, a list of CSAPR NO_X Ozone Season Group 2 units and the amount of CSAPR NO_X Ozone Season Group 2 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and that commenced commercial operation before January 1, 2015;

* * * * *

(8) *Abbreviated SIP revisions replacing certain provisions of the Federal CSAPR NO_X Ozone Season Group 2 Trading Program.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart EEEEE of part 97 of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 5 TO PARAGRAPH (b)(8)(iii)(B)

Year of the control period for which CSAPR NO_X Ozone Season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2019 or 2020	June 1, 2018.
2021 or 2022	June 1, 2019.
2023 or 2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(8)(iii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(8)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(8)(iii) of this section.

(9) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 2 Trading Programs.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 2 Trading Program set forth in §§ 97.802 through 97.835 of this chapter, except that the SIP revision:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 6 TO PARAGRAPH (b)(9)(iii)(B)

Year of the control period for which CSAPR NO_X Ozone Season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2019 or 2020	June 1, 2018.
2021 or 2022	June 1, 2019.
2023 or 2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that, if and when any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.802 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.806(c)(2), and 97.825 of this chapter and the portions of other provisions of subpart EEEEE of part 97 of this chapter referencing §§ 97.802, 97.806(c)(2), and 97.825 and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(9)(iii) through (vi) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(9)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(9)(iii) of this section.

(10) *State-determined allocations of CSAPR NO_X Ozone Season Group 3 allowances for 2024.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 3 allowance allocation provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2024, a list of CSAPR NO_X Ozone Season Group 3 units and the amount of CSAPR NO_X Ozone Season Group 3 allowances

allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and that commenced commercial operation before January 1, 2021;

(ii) The total amount of CSAPR NO_X Ozone Season Group 3 allowance allocations on the list must not exceed the amount, under § 97.1010 of this chapter for the State and the control period in 2024, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the Indian country existing unit set-aside and the new unit set-aside;

* * * * *

(v) * * *

(A) By August 4, 2023, the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraphs (b)(10)(i) through (iv) of this section by September 1, 2023; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (b)(10)(v)(A) of this section by September 1, 2023.

(11) *Abbreviated SIP revisions replacing certain provisions of the Federal CSAPR NO_X Ozone Season Group 3 Trading Program.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart GGGGG of part 97 of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the Indian country existing unit set-aside, the new unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator;

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(11)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter; and

(iv) Provided that the State must submit a complete SIP revision meeting the requirements of paragraph (b)(11)(iii) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(11)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(11)(iii) of this section.

(12) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 3 Trading Programs.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program set forth in §§ 97.1002 through 97.1035 of this chapter, except that the SIP revision:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the Indian country existing unit set-aside, the new unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator;

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(12)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter;

* * * * *

(vi) Must not include any of the requirements imposed on any unit in areas of Indian country within the borders of the State not subject to the State's SIP authority in the provisions in §§ 97.1002 through 97.1035 of this chapter and must not include the provisions in §§ 97.1011(a)(2), 97.1012, and 97.1021(g) through (j) of this chapter, all of which provisions will continue to apply under any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vii) Provided that, if before the Administrator's approval of the SIP revision any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority before the Administrator's approval of the SIP revision, the SIP revision must exclude the provisions in §§ 97.1002 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.1006(c)(2), and 97.1025 of this chapter and the portions of other provisions of subpart GGGGG of part 97 of this chapter referencing §§ 97.1002, 97.1006(c)(2), and 97.1025, and further provided that, if and when after the Administrator's approval of the SIP revision any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority, the Administrator may modify his or her approval of the SIP revision to exclude these provisions and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

(viii) Provided that the State must submit a complete SIP revision meeting the requirements of paragraphs (b)(12)(iii) through (vi) of this section by December 1 of the year before the year of the deadline for submission of allocations or auction results under paragraph (b)(12)(iii)(B) of this section applicable to the first control period for which the State wants to make allocations or hold an auction under paragraph (b)(12)(iii) of this section.

(13) *Withdrawal of CSAPR FIP provisions relating to NO_X ozone season emissions; satisfaction of NO_X SIP Call requirements.* Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the

CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section, paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section, or paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section for sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority—

(i) Except as provided in paragraph (b)(14) of this section, the provisions of paragraph (b)(2)(i), (ii), or (iii) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision; and

* * * * *

(14) * * *

(ii) Notwithstanding the provisions of paragraph (b)(13)(i) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 1 allowances under subpart BBBBB of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(iii) Notwithstanding any discontinuation pursuant to paragraph (b)(2)(i)(B), (b)(2)(ii)(B) or (C), or (b)(13)(i) of this section of the applicability of subpart BBBBB or EEEEE of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(A) The provisions of §§ 97.526(c) and 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances between certain Allowance Management System accounts under common control);

(B) The provisions of §§ 97.526(d) and 97.826(d) and (e) of this chapter (concerning the conversion of unused CSAPR NO_X Ozone Season Group 1 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances and the conversion of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 3 allowances); and

(C) The provisions of § 97.811(d) and (e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all CSAPR NO_X Ozone Season Group 2 allowances allocated for specified control periods and recorded in specified Allowance Management System accounts).

(15) * * *

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(4) of this section as replacing the CSAPR NO_X Ozone Season Group 1 allowance allocation provisions in §§ 97.511(a) and (b)(1) and 97.512(a) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2017 or any subsequent year: [none].

* * * * *

(16) * * *

(i) * * *

(B) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(8) of this section as replacing the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in §§ 97.811(a) and (b)(1) and 97.812(a) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2019 or any subsequent year: New York.

(C) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(9) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: Alabama, Indiana, and Missouri.

(ii) * * *

(B) Notwithstanding any provision of subpart EEEEE of part 97 of this chapter or any State's SIP, with regard to any State listed in paragraph (b)(2)(ii)(C) of this section and any control period that begins after December 31, 2022, the Administrator will not carry out any of the functions set forth for the Administrator in subpart EEEEE of part 97 of this chapter, except §§ 97.811(e) and 97.826(c) and (e) of this chapter, or in any emissions trading program provisions in a State's SIP approved under paragraph (b)(8) or (9) of this section.

(17) * * *

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(10) of this section as replacing the CSAPR NO_X Ozone Season Group 3 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2024: [none].

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(11) of this section as replacing the CSAPR NO_X Ozone Season Group 3 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for the control period in 2025 or any subsequent year: [none].

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(12) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: [none].

■ 3. Amend § 52.39 by:
■ a. In paragraph (a), removing "(SO_2), except" and adding in its place "(SO_2) for sources meeting the applicability criteria set forth in subparts CCCCC and DDDDD, except";
■ b. In paragraph (d) introductory text, removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";
■ c. In paragraph (d)(1), removing "State and" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority and that";
■ d. In paragraph (e) introductory text, removing "for the State's sources, and" and adding in its place "with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and";
■ e. Revising table 1 to paragraph (e)(1)(ii);
■ f. In paragraph (e)(2), removing "deadlines for submission of allocations or auction results under paragraphs (e)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (e)(1)(ii)";
■ g. In paragraph (f) introductory text, removing "State (but not sources in any Indian country within the borders of the State), regulations" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations";
■ h. Revising table 2 to paragraph (f)(1)(ii);
■ i. In paragraph (f)(4), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority";
■ j. In paragraph (f)(5), removing "Indian country within the borders of the State, the" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority, the";
■ k. In paragraph (f)(6), removing "deadlines for submission of allocations or auction results under paragraphs (f)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (f)(1)(ii)";
■ l. In paragraph (g) introductory text:
■ i. Removing "(c)(1) or (2)" and adding in its place "(c)"; and
■ ii. Removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";
■ m. In paragraph (g)(1), removing "State and" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority and that";
■ n. In paragraph (h) introductory text, removing "for the State's sources, and" and adding in its place "with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, and";
■ o. Revising table 3 to paragraph (h)(1)(ii);
■ p. In paragraph (h)(2), removing "deadlines for submission of allocations or auction results under paragraphs (h)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (h)(1)(ii)";
■ q. In paragraph (i) introductory text, removing "State (but not sources in any Indian country within the borders of the State), regulations" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations";
■ r. Revising table 4 to paragraph (i)(1)(ii);
■ s. In paragraph (i)(4), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority";
■ t. In paragraph (i)(5), removing "Indian country within the borders of the State, the" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority, the";
■ u. In paragraph (i)(6), removing "deadlines for submission of allocations or auction results under paragraphs (i)(1)(ii) and (iii)" and adding in its place "deadline for submission of allocations or auction results under paragraph (i)(1)(ii)";
■ v. Revising paragraphs (j) and (k)(2);
■ w. Adding paragraph (k)(3);
■ x. In paragraphs (l)(1) and (2), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for";
■ y. In paragraph (l)(3), removing "State (but not sources in any Indian country within the borders of the State):" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority:".
■ z. In paragraphs (m)(1) and (2), removing "the State and" and adding in its place "sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for"; and
■ aa. In paragraph (m)(3), removing "State (but not sources in any Indian country within the borders of the State):" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority:".

The revisions and addition read as follows:

§ 52.39 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of sulfur dioxide?

* * * * *

(e) * * *

(1) * * *

(ii) * * *

TABLE 1 TO PARAGRAPH (e)(1)(ii)

Year of the control period for which CSAPR SO_2 group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(f) * * *

(1) * * *

(ii) * * *

TABLE 2 TO PARAGRAPH (f)(1)(ii)

Year of the control period for which CSAPR SO_2 group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(h) * * *

(1) * * *

(ii) * * *

TABLE 3 TO PARAGRAPH (h)(1)(ii)

Year of the control period for which CSAPR SO_2 group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(i) * * *

(1) * * *

(ii) * * *

TABLE 4 TO PARAGRAPH (i)(1)(ii)

Year of the control period for which CSAPR SO_2 group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the administrator
2017 or 2018	June 1, 2016.
2019 or 2020	June 1, 2017.
2021 or 2022	June 1, 2018.
2023	June 1, 2019.
2024	June 1, 2020.
2025 or any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(j) *Withdrawal of CSAPR FIP provisions relating to SO_2 emissions.* Except as provided in paragraph (k) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section or paragraphs (a), (c)(1), (g), and (h) of this section for sources in the State and Indian country within the borders of the State subject to the State's SIP authority, the provisions of paragraph (b) or (c)(1) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(k) * * *

(2) Notwithstanding the provisions of paragraph (j) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter, or allocations of CSAPR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(3) Notwithstanding any discontinuation pursuant to paragraph

(c)(2) or (j) of this section of the applicability of subpart CCCCC or DDDDD of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR SO_2 Group 1 allowances and CSAPR SO_2 Group 2 allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

(i) The provisions of §§ 97.626(c) and 97.726(c) of this chapter (concerning the transfer of CSAPR SO_2 Group 1 allowances and CSAPR SO_2 Group 2 allowances between certain Allowance Management System accounts under common control).

(ii) [Reserved]

* * * * *

■ 4. Add §§ 52.40 through 52.46 to subpart A to read as follows:

Sec.

* * * * *

52.40 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from sources not subject to the CSAPR ozone season trading program?

52.41 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Pipeline Transportation of Natural Gas Industry?

52.42 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Cement and Concrete Product Manufacturing Industry?

52.43 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Iron and Steel Mills and Ferroalloy Manufacturing Industry?

52.44 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Glass and Glass Product Manufacturing Industry?

52.45 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, the Pulp, Paper, and Paperboard Mills Industries, Metal Ore Mining, and the Iron and Steel and Ferroalloy Manufacturing Industries?

52.46 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from Municipal Waste Combustors?

* * * * *

§ 52.40 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from sources not subject to the CSAPR ozone season trading program?

(a) *Purpose.* This section establishes Federal Implementation Plan requirements for new and existing units in the industries specified in paragraph (b) of this section to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 8-hour ozone National Ambient Air Quality Standards in other states pursuant to 42 U.S.C. 7410(a)(2)(D)(i)(I).

(b) *Definitions.* The terms used in this section and §§ 52.41 through § 52.46 are defined as follows:

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Existing affected unit means any affected unit for which construction commenced before August 4, 2023.

New affected unit means any affected unit for which construction commenced on or after August 4, 2023.

Operator means any person who operates, controls, or supervises an affected unit and shall include, but not be limited to, any holding company, utility system, or plant manager of such affected unit.

Owner means any holder of any portion of the legal or equitable title in an affected unit.

Potential to emit means the maximum capacity of a unit to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the unit to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a unit.

Rolling average means the weighted average of all data, meeting quality assurance and quality control (QA/QC) requirements in this part or otherwise normalized, collected during the applicable averaging period. The period of a rolling average stipulates the frequency of data averaging and reporting. To demonstrate compliance with an operating parameter a 30-day rolling average period requires calculation of a new average value each operating day and shall include the average of all the hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit based on pollutant concentration, a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. For demonstration of compliance with an emissions limit based on lbs-pollutant per production unit, the 30-day rolling average is calculated by summing the hourly mass emissions over the previous 30 operating days, then dividing that sum by the total production during the same period.

(c) *General requirements.* (1) The NO_X emissions limitations or emissions control requirements and associated compliance requirements for the following listed source categories not subject to the CSAPR ozone season trading program constitute the Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season (defined as May 1 through September 30 of a calendar year): §§ 52.41 for engines in the Pipeline Transportation of Natural Gas Industry, 52.42 for kilns in the Cement and Concrete Product Manufacturing Industry, 52.43 for reheat furnaces in the Iron and Steel Mills and Ferroalloy Manufacturing Industry, 52.44 for furnaces in the Glass and Glass Product Manufacturing Industry, 52.45 for boilers in the Iron and Steel Mills and Ferroalloy Manufacturing, Metal Ore Mining, Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills industries, and 52.46 for Municipal Waste Combustors.

(2) The provisions of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 apply to affected units located in each of the following States, including Indian country located within the borders of such States, beginning in the 2026 ozone season and in each subsequent ozone season: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, and West Virginia.

(3) The testing, monitoring, recordkeeping, and reporting requirements of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 only apply during the ozone season, except as otherwise specified in these sections. Additionally, if an owner or operator of an affected unit chooses to conduct a performance or compliance test outside of the ozone season, all recordkeeping, reporting, and notification requirements associated

with that test shall apply, without regard to whether they occur during the ozone season.

(d) *Requests for extension of compliance.* (1) The owner or operator of an existing affected unit under § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that cannot comply with the applicable requirements in those sections by May 1, 2026, due to circumstances entirely beyond the owner or operator's control, may request an initial compliance extension to a date certain no later than May 1, 2027. The extension request must contain a demonstration of necessity consistent with the requirements of paragraph (d)(3) of this section.

(2) If, after the EPA has granted a request for an initial compliance extension, the source remains unable to comply with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 by the extended compliance date due to circumstances entirely beyond the owner or operator's control, the owner or operator may apply for a second compliance extension to a date certain no later than May 1, 2029. The extension request must contain an updated demonstration of necessity consistent with the requirements of paragraph (d)(3) of this section.

(3) Each request for a compliance extension shall demonstrate that the owner or operator has taken all steps possible to install the controls necessary for compliance with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 by the applicable compliance date and shall:

(i) Identify each affected unit for which the owner or operator is seeking the compliance extension;

(ii) Identify and describe the controls to be installed at each affected unit to comply with the applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46;

(iii) Identify the circumstances entirely beyond the owner or operator's control that necessitate additional time to install the identified controls;

(iv) Identify the date(s) by which on-site construction, installation of control equipment, and/or process changes will be initiated;

(v) Identify the owner or operator's proposed compliance date. A request for an initial compliance extension under paragraph (d)(1) of this section must specify a proposed compliance date no later than May 1, 2027, and state whether the owner or operator anticipates a need to request a second compliance extension. A request for a second compliance extension under paragraph (d)(2) of this section must specify a proposed compliance date no later than May 1, 2029, and identify additional actions taken by the owner or operator to ensure that the affected unit(s) will be in compliance with the applicable requirements in this section by that proposed compliance date;

(vi) Include all information obtained from control technology vendors demonstrating that the identified controls cannot be installed by the applicable compliance date;

(vii) Include any and all contract(s) entered into for the installation of the identified controls or an explanation as to why no contract is necessary or obtainable; and

(viii) Include any permit(s) obtained for the installation of the identified controls or, where a required permit has not yet been issued, a copy of the permit application submitted to the permitting authority and a statement from the permitting authority identifying its anticipated timeframe for issuance of such permit(s).

(4) Each request for a compliance extension shall be submitted via the Compliance and Emissions Data Reporting Interface (CEDRI) or analogous electronic submission system provided by the EPA no later than 180 days prior to the applicable compliance date. Until an extension has been granted by the Administrator under this section, the owner or operator of an affected unit shall comply with all applicable requirements of this section and shall remain subject to the May 1, 2026 compliance date or the initial extended compliance date, as applicable. A denial will be effective as of the date of denial.

(5) The owner or operator of an affected unit who has requested a compliance extension under this paragraph (d)(5) and is required to have a title V permit shall apply to have the relevant title V permit revised to incorporate the conditions of the extension of compliance. The conditions of a compliance extension granted under this paragraph (d)(5) will be incorporated into the affected unit's title V permit according to the provisions of an EPA-approved state operating permit program or the Federal title V regulations in 40 CFR part 71, whichever apply.

(6) Based on the information provided in any request made under paragraph (d) of this section or other information, the Administrator may grant an extension of time to comply with applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 consistent with the provisions of paragraph (d)(1) or (2) of this section. The decision to grant an extension will be provided by notification via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will identify each affected unit covered by the extension; specify the termination date of the extension; and specify any additional conditions that the Administrator deems necessary to ensure timely installation of the necessary controls (*e.g.,* the date(s) by which on-site construction, installation of control equipment, and/or process changes will be initiated).

(7) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator of an affected unit who has requested a compliance extension under this paragraph (d)(7) whether the submitted request is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original request and within 60 calendar days after receipt of any supplementary information.

(8) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA, which shall be publicly available, to the owner or operator of a decision to grant or intention to deny a request for a compliance extension within 60 calendar days after providing written notification pursuant to paragraph (d)(7) of this section that the submitted request is complete.

(9) Before denying any request for an extension of compliance, the Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator in writing of the Administrator's intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present via the CEDRI or analogous electronic submission system provided by the EPA, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(10) The Administrator's final decision to deny any request for an extension will be provided via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will set forth the specific grounds on which the denial is based. The final decision will be made within 60 calendar days after presentation of additional information

or argument (if the request is complete), or within 60 calendar days after the deadline for the submission of additional information or argument under paragraph (d)(9)(ii) of this section, if no such submission is made.

(11) The granting of an extension under this section shall not abrogate the Administrator's authority under section 114 of the Clean Air Act (CAA or the Act).

(e) *Requests for case-by-case emissions limits.* (1) The owner or operator of an existing affected unit under § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that cannot comply with the applicable requirements in those sections due to technical impossibility or extreme economic hardship may submit to the Administrator, by August 5, 2024, a request for approval of a case-by-case emissions limit. The request shall contain information sufficient for the Administrator to confirm that the affected unit is unable to comply with the applicable emissions limit, due to technical impossibility or extreme economic hardship, and to establish an appropriate alternative case-by-case emissions limit for the affected unit. Until a case-by-case emissions limit has been approved by the Administrator under this section, the owner or operator shall remain subject to all applicable requirements in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46. A denial will be effective as of the date of denial.

(2) Each request for a case-by-case emissions limit shall include, but not be limited to, the following:

(i) A demonstration that the affected unit cannot achieve the applicable emissions limit with available control technology due to technical impossibility or extreme economic hardship.

(A) A demonstration of technical impossibility shall include:

(*1*) Uncontrolled NO_X emissions for the affected unit established with a CEMS, or stack tests obtained during steady state operation in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii)(2), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking; and

(*2*) A demonstration that the affected unit cannot meet the applicable emissions limit even with available control technology, including:

(*i*) Stack test data or other emissions data for the affected unit; or

(*ii*) A third-party engineering assessment demonstrating that the affected unit cannot meet the applicable emissions limit with available control technology.

(B) A demonstration of extreme economic hardship shall include at least three vendor estimates of the costs of installing control technology necessary to meet the applicable emissions limit and other information that demonstrates, to the satisfaction of the Administrator, that the cost of complying with the applicable emissions limit would present an extreme economic hardship relative to the costs borne by other comparable sources in the industry.

(ii) An analysis of available control technology options and a proposed case-by-case emissions limit that represents the lowest emissions limitation technically achievable by the affected unit without causing extreme economic hardship relative to the costs borne by other comparable sources in the industry. The owner or operator may propose additional measures to reduce NO_X emissions, such as operational standards or work practice standards.

(iii) Calculations of the NO_X emissions reduction to be achieved through implementation of the proposed case-by-case emissions limit and any additional proposed measures, the difference between this NO_X emissions reduction level and the NO_X emissions reductions that would have occurred if the affected unit complied with the applicable emissions limitations in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46, and a description of the methodology used for these calculations.

(3) The owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph (e)(3) and is required to have a title V permit shall apply to have the relevant title V permit revised to incorporate the case-by-case emissions limit. Any case-by-case emissions limit approved under this paragraph (e)(3) will be incorporated into the affected unit's title V permit according to the provisions of an EPA-approved state operating permit program or the Federal title V regulations in 40 CFR part 71, whichever apply.

(4) Based on the information provided in any request made under this paragraph (e)(4) or other information, the Administrator may approve a case-by-case emissions limit that will apply to an affected unit in lieu of the applicable emissions limit in § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46. The decision to approve a case-by-case emissions limit will be provided via the CEDRI or analogous electronic submission system provided by the EPA in paragraph (d) of this section and publicly available, and will identify each affected unit covered by the case-by-case emissions limit.

(5) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA in paragraph (d) of this section to the owner or operator of an affected unit who has requested a case-by-case emissions limit under this paragraph (e)(5) whether the submitted request is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original request and within 60 calendar days after receipt of any supplementary information.

(6) The Administrator will provide notification via the CEDRI or analogous electronic submission system described by the EPA in paragraph (d) of this section, which shall be publicly available, to the owner or operator of a decision to approve or intention to deny the request within 60 calendar days after providing notification pursuant to paragraph (e)(5) of this section that the submitted request is complete.

(7) Before denying any request for a case-by-case emissions limit, the Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA to the owner or operator in writing of the Administrator's intention to issue the denial, together with:

(i) Notice of the information and findings on which the intended denial is based; and

(ii) Notice of opportunity for the owner or operator to present via the CEDRI or analogous electronic submission system provided by the EPA, within 15 calendar days after he/she is notified of the intended denial, additional information or arguments to the Administrator before further action on the request.

(8) The Administrator's final decision to deny any request for a case-by-case emissions limit will be provided by notification via the CEDRI or analogous electronic submission system provided by the EPAand publicly available, and will set forth the specific grounds on which the denial is based. The final decision will be made within 60 calendar days after presentation of additional information or argument (if the request is complete), or within 60 calendar days after the deadline for the

submission of additional information or argument under paragraph (e)(7)(ii) of this section, if no such submission is made.

(9) The approval of a case-by-case emissions limit under this section shall not abrogate the Administrator's authority under section 114 of the Act.

(f) *Recordkeeping requirements.* (1) The owner or operator of an affected unit subject to the provisions of this section or § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 shall maintain files of all information (including all reports and notifications) required by these sections recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

(2) Any records required to be maintained by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 that are submitted electronically via the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(g) *CEDRI reporting requirements.* (1) You shall submit the results of the performance test following the procedures specified in paragraphs (g)(1)(i) through (iii) of this section:

(i) Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (*https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert*) at the time of the test. Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(ii) Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test. The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii)(A) The EPA will make all the information submitted through CEDRI available to the public without further notice to you. Do not use CEDRI to submit information you claim as confidential business information (CBI). Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (g)(1) or (2) of this section, you should submit a complete file, including information claimed to be CBI, to the EPA.

(B) The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website.

(C) Clearly mark the part or all of the information that you claim to be CBI. Information not marked as CBI may be authorized for public release without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

(D) The preferred method to receive CBI is for it to be transmitted electronically using email attachments, File Transfer Protocol, or other online file sharing services. Electronic submissions must be transmitted directly to the Office of Air Quality Planning and Standards (OAQPS) CBI Office at the email address *oaqpscbi@epa.gov*, and as described in this paragraph (g), should include clear CBI markings and be flagged to the attention of Lead of 2015 Ozone Transport FIP. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link.

(E) If you cannot transmit the file electronically, you may send CBI information through the postal service to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Lead of 2015 Ozone Transport FIP. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

(F) All CBI claims must be asserted at the time of submission. Anything submitted using CEDRI cannot later be claimed CBI. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(G) You must submit the same file submitted to the CBI office with the CBI omitted to the EPA via the EPA's CDX as described in paragraphs (g)(1) and (2) of this section.

(2) Annual reports must be submitted via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (g)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (g)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected unit, its contractors, or any entity controlled by the affected unit that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected unit (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.41 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Pipeline Transportation of Natural Gas Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an engine meeting the applicability criteria of this section.

Cap means the total amount of NO_X emissions, in tons per day on a 30-day rolling average basis, that is collectively allowed from all of the affected units covered by a Facility-Wide Averaging Plan and is calculated as the sum each affected unit's NO_X emissions at the emissions limit applicable to such unit under paragraph (c) of this section, converted to tons per day in accordance with paragraph (d)(3) of this section.

Emergency engine means any stationary reciprocating internal combustion engine (RICE) that meets all of the criteria in paragraphs (i) and (ii) of this definition. All emergency stationary RICE must comply with the requirements specified in paragraph (b)(1) of this section in order to be considered emergency engines. If the engine does not comply with the requirements specified in paragraph (b)(1), it is not considered an emergency engine under this section.

(i) The stationary engine is operated to provide electrical power or mechanical work during an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, etc.

(ii) The stationary RICE is operated under limited circumstances for purposes other than those identified in paragraph (i) of this definition, as specified in paragraph (b)(1) of this section.

Facility means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same first two digit code as described in the Standard Industrial Classification Manual, 1987). For purposes of this section, a facility may not extend beyond the 20 states identified in § 52.40(b)(2).

Four stroke means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity, and 101.3 kilopascals pressure.

Lean burn means any two-stroke or four-stroke spark ignited reciprocating internal combustion engine that does not meet the definition of a rich burn engine.

Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, but not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are within a single state that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems. LDCs do not include pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

Local Distribution Company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Nameplate rating means the manufacturer's maximum design capacity in horsepower (hp) at the installation site conditions. Starting from the completion of any physical change in the engine resulting in an increase in the maximum output (in hp) that the engine is capable of producing on a steady state basis and during continuous operation, such increased maximum output shall be as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) or non-hydrocarbons, composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired means that greater than or equal to 90% of the engine's heat input, excluding recirculated or recuperated exhaust heat, is derived from the combustion of natural gas.

Natural gas processing plant means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas production facility means all equipment at a single stationary source directly associated with one or more natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline.

Operating day means a 24-hour period beginning at 12:00 midnight during which any fuel is combusted at any time in the engine.

Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, including the compressor and pipeline network used to transport the natural gas from processing plants over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and prior to delivery to a ''local distribution company custody transfer station'' (as defined in this section) of an LDC that provides the natural gas to end-users. *Pipeline transportation of natural gas* does not include natural gas production facilities, natural gas processing plants, or the portion of a compressor and pipeline network that is upstream of a natural gas processing plant.

Reciprocating internal combustion engine (RICE) means a reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.

Rich burn means any four-stroke spark ignited reciprocating internal combustion engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Internal combustion engines originally manufactured as rich burn engines but modified with passive emissions control technology for nitrogen oxides (NO_X) (such as pre-combustion chambers) will be considered lean burn engines. Existing affected unit where there are no manufacturer's recommendations regarding air/fuel ratio will be considered rich burn engines if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Spark ignition means a reciprocating internal combustion engine utilizing a spark plug (or other sparking device) to ignite the air/fuel mixture and with operating characteristics significantly similar to the theoretical Otto combustion cycle.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Two stroke means a type of reciprocating internal combustion engine which completes the power cycle in a single crankshaft revolution by combining the intake and compression operations into one stroke (one-half revolution) and the power and exhaust operations into a second stroke. This system requires auxiliary exhaust scavenging of the combustion products and inherently runs lean (excess of air) of stoichiometry.

(b) *Applicability.* You are subject to the requirements under this section if you own or operate a new or existing natural gas-fired spark ignition engine, other than an emergency engine, with a nameplate rating of 1,000 hp or greater that is used for pipeline transportation of natural gas and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).

(1) For purposes of this section, the owner or operator of an emergency stationary RICE must operate the RICE according to the requirements in paragraphs (b)(1)(i) through (iii) of this section to be treated as an emergency stationary RICE. In order for stationary RICE to be treated as an emergency RICE under this subpart, any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for up to 50 hours per year, as described in paragraphs (b)(1)(i) through (iii), is prohibited. If you do not operate the RICE according to the requirements in paragraphs (b)(1)(i) through (iii), the RICE will not be considered an emergency engine under this section and must meet all requirements for affected units in this section.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) The owner or operator may operate your emergency stationary RICE for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by a Federal, state, or local government agency, the manufacturer, the vendor, or the insurance company associated with the engine. Any operation for non-emergency situations as allowed by paragraph (b)(1)(iii) of this section counts as part of the 100 hours per calendar year allowed by paragraph (b)(1)(ii) of this section. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records confirming that Federal, state, or local standards require maintenance and testing of emergency RICE beyond 100 hours per calendar year. Any approval of a petition for additional hours granted by the Administrator under 40 CFR part 63, subpart ZZZZ, shall constitute approval by the Administrator of the same petition under this paragraph (b)(1)(ii).

(iii) Emergency stationary RICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing provided in paragraph (b)(1)(ii) of this section.

(2) If you own or operate a natural gas-fired two stroke lean burn spark ignition engine manufactured after July 1, 2007 that is meeting the applicable emissions limits in 40 CFR part 60, subpart JJJJ, table 1, the engine is not an affected unit under this section and you do not have to comply with the requirements of this section.

(3) If you own or operate a natural gas-fired four stroke lean or rich burn spark ignition engine manufactured after July 1, 2010, that is meeting the applicable emissions limits in 40 CFR part 60, subpart JJJJ, table 1, the engine is not an affected unit under this section and you do not have to comply with the requirements of this section.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Natural gas-fired four stroke rich burn spark ignition engine: 1.0 grams per hp-hour (g/hp-hr);

(2) Natural gas-fired four stroke lean burn spark ignition engine: 1.5 g/hp-hr; and

(3) Natural gas-fired two stroke lean burn spark ignition engine: 3.0 g/hp-hr.

(d) *Facility-Wide Averaging Plan.* If you are the owner or operator of a facility containing more than one affected unit, you may submit a request via the CEDRI or analogous electronic submission system provided by the EPA to the Administrator for approval of a proposed Facility-Wide Averaging Plan as an alternative means of compliance with the applicable emissions limits in paragraph (c) of this section. Any such request shall be submitted to the Administrator on or before October 1st of the year prior to each emissions averaging year. The Administrator will approve a proposed Facility-Wide Averaging Plan submitted under this paragraph (d) if the Administrator determines that the proposed Facility-Wide Averaging Plan meets the requirements of this paragraph (d), will provide total emissions reductions equivalent to or greater than those achieved by the applicable emissions limits in paragraph (c), and identifies satisfactory means for determining initial and continuous compliance, including appropriate testing, monitoring, recordkeeping, and reporting requirements. You may only include affected units (*i.e.,* engines meeting the applicability criteria in paragraph (b) of this section) in a Facility-Wide Averaging Plan. Upon EPA approval of a proposed Facility-Wide Averaging Plan, you cannot withdraw any affected unit listed in such plan, and the terms of the plan may not be changed unless approved in writing by the Administrator.

(1) Each request for approval of a proposed Facility-Wide Averaging Plan shall include, but not be limited to:

(i) The address of the facility;

(ii) A list of all affected units at the facility that will be covered by the plan, identified by unit identification number, the engine manufacturer's name, and model;

(iii) For each affected unit, a description of any existing NO_X emissions control technology and the date of installation, and a description of any NO_X emissions control technology to be installed and the projected date of installation;

(iv) Identification of the emissions cap, calculated in accordance with paragraph (d)(3) of this section, that all affected units covered by the proposed Facility-Wide Averaging Plan will be subject to during the ozone season, together with all assumptions included in such calculation; and

(iv) Adequate provisions for testing, monitoring, recordkeeping, and reporting for each affected unit.

(2) Upon the Administrator's approval of a proposed Facility-Wide Averaging Plan, the owner or operator of the affected units covered by the Facility-Wide Averaging Plan shall comply with the cap identified in the plan in lieu of the emissions limits in paragraph (c) of this section. You will be in compliance with the cap if the sum of NO_X emissions from all units covered by the Facility-Wide Averaging Plan, in tons per day on a 30-day rolling average basis, is less than or equal to the cap.

(3) The owner or operator will calculate the cap according to equation 1 to this paragraph (d)(3). You will monitor and record daily hours of engine operation for use in calculating the cap on a 30-day rolling average basis. You will base the hours of operation on hour readings from a non-resettable hour meter or an equivalent monitoring device.

Equation 1 to Paragraph (d)(3)

$$Cap\ (tons\ per\ day) = 907{,}184.74\ x \sum_{i=1}^{N} (R_{li}\ x\ DC\ x\ H_i)$$

Where:

H_i = the average daily operating hours based on the highest consecutive 30-day period during the ozone season of the two most recent years preceding the emissions averaging year (hours).
i = each affected unit included in the Cap.
N = number of affected units.
DC = the engine manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions.
R_{li} = the emissions limit for each affected unit from paragraph (c) of this section (grams/hp-hr).

(i) Any affected unit for which less than two years of operating data are available shall not be included in the Facility-Wide Averaging Plan unless the owner or operator extrapolates the available operating data for the affected unit to two years of operating data, for use in calculating the emissions cap in accordance with paragraph (d)(3) of this section.

(ii) [Reserved]

(4) The owner or operator of an affected units covered by an EPA-approved Facility-Wide Averaging Plan will be in violation of the cap if the sum of NO_X emissions from all such units, in tons per day on a 30-day rolling average basis, exceeds the cap. Each day of noncompliance by each affected unit covered by the Facility-Wide Averaging Plan shall be a violation of the cap until corrective action is taken to achieve compliance.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit subject to a NO_X emissions limit under paragraph (c) of this section, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3)(i) If you are the owner or operator of a new affected unit, you must conduct an initial performance test within six months of engine startup and conduct subsequent performance tests every twelve months thereafter to demonstrate compliance. If pollution control equipment is installed to comply with a NO_X emissions limit in paragraph (c) of this section, however, the initial performance test shall be conducted within 90 days of such installation.

(ii) If you are the owner or operator of an existing affected unit, you must conduct an initial performance test within six months of becoming subject to an emissions limit under paragraph (c) of this section and conduct subsequent performance tests every twelve months thereafter to demonstrate compliance. If pollution control equipment is installed to comply with a NO_X emissions limit in paragraph (c) of this section, however, the initial performance test shall be conducted within 90 days of such installation.

(iii) If you are the owner or operator of a new or existing affected unit that is only operated during peak demand periods outside of the ozone season and the engine's hours of operation during the ozone season are 50 hours or less, the affected unit is not subject to the testing and monitoring requirements of this paragraph (e)(3)(iii) as long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g) of this section.

(iv) If you are the owner or operator of an affected unit, you must conduct all performance tests consistent with the requirements of 40 CFR 60.4244 in accordance with the applicable reference test methods identified in table 2 to subpart JJJJ of 40 CFR part 60, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. To determine compliance with the NO_X emissions limit in paragraph (c) of this section, the emissions rate shall be calculated in accordance with the requirements of 40 CFR 60.4244(d).

(4) If you are the owner or operator of an affected unit that has a non-selective catalytic reduction (NSCR) control device to reduce emissions, you must:

(i) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within the observed inlet temperature range from the most recent performance test or the temperatures specified by the manufacturer if no performance test was required by this section; and

(ii) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop across the catalyst changes by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst measured during the most recent performance test.

(5) If you are the owner of operator of an affected unit not using an NSCR control device to reduce emissions, you are required to conduct continuous parametric monitoring to assure compliance with the applicable emissions limits according to the requirements in paragraphs (e)(5)(i) through (vi) of this section.

(i) You must prepare a site-specific monitoring plan that includes all of the following monitoring system design, data collection, and quality assurance and quality control elements:

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(C) Equipment performance evaluations, system accuracy audits, or other audit procedures.

(D) Ongoing operation and maintenance procedures in accordance with the requirements of paragraph (e)(1) of this section.

(E) Ongoing recordkeeping and reporting procedures in accordance with the requirements of paragraphs (f) and (g) of this section.

(ii) You must continuously monitor the selected operating parameters according to the procedures in your site-specific monitoring plan.

(iii) You must collect parametric monitoring data at least once every 15 minutes.

(iv) When measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(v) You must conduct performance evaluations, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(vi) You must conduct a performance evaluation of each parametric monitoring device in accordance with your site-specific monitoring plan.

(6) If you are the owner or operator of an affected unit that is only operated during peak periods outside of the ozone season and your hours of operation during the ozone season are 0, you are not subject to the testing and monitoring requirements of this paragraph (e)(6) so long as you record and report your hours of operation during the ozone season in accordance with paragraphs (f) and (g) of this section.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you must keep records of:

(1) Performance tests conducted pursuant to paragraph (e)(2) of this section, including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

(2) Catalyst monitoring required by paragraph (e)(3) of this section, if applicable, and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

(3) Parameters monitored pursuant to the facility's site-specific parametric monitoring plan.

(4) Hours of operation on a daily basis.

(5) Tuning, adjustments, or other combustion process adjustments and the date of the adjustment(s).

(6) For any Facility-Wide Averaging Plan approved by the Administrator under paragraph (d) of this section, daily calculations of total NO_X emissions to demonstrate compliance with the cap during the ozone season. You must use the equation in this paragraph (f)(6) to calculate total NO_X emissions from all affected units covered by the Facility-Wide Averaging Plan, in tons per day on a 30-day rolling average basis, for purposes of determining compliance with the cap during the ozone season. A new 30-day rolling average emissions rate in tpd is calculated for each operating day during the ozone season, using the 30-day rolling average daily operating hours for the preceding 30 operating days.

Equation 2 to Paragraph (f)(6)

$$\sum_{i=1}^{N}(R_{ai}\ x\ DC\ x\ H_{ai}) \leq Cap\ (tons\ per\ day)$$

Where:

H_{ai} = the consecutive 30-day rolling average daily operating hours for the preceding 30 operating days during ozone season (hours).
i = each affected unit.
N = number of affected units.
DC = the engine manufacturer's maximum design capacity in horsepower (hp) at the installation site conditions.
R_{ai} = the actual emissions rate for each affected unit based on the most recent performance test results, (grams/hp-hr).

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you are the owner or operator of an affected unit, you must submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in paragraph (g) of this section. The report shall contain the following information:

(i) The name and address of the owner and operator;

(ii) The address of the subject engine;

(iii) Longitude and latitude coordinates of the subject engine;

(iv) Identification of the subject engine;

(v) Statement of compliance with the applicable emissions limit under paragraph (c) of this section or a Facility-Wide Averaging Plan under paragraph (d) of this section;

(vi) Statement of compliance regarding the conduct of maintenance and operations in a manner consistent with good air pollution control practices for minimizing emissions;

(vii) The date and results of the performance test conducted pursuant to paragraph (e) of this section;

(viii) Any records required by paragraph (f) of this section, including records of parametric monitoring data, to demonstrate compliance with the applicable emissions limit under paragraph (c) of this section or a Facility-Wide Averaging Plan under paragraph (d) of this section, if applicable;

(ix) If applicable, a statement documenting any change in the operating characteristics of the subject engine; and

(x) A statement certifying that the information included in the annual report is complete and accurate.

§ 52.42 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Cement and Concrete Product Manufacturing Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means a cement kiln meeting the applicability criteria of this section.

Cement kiln means an installation, including any associated pre-heater or pre-calciner devices, that produces clinker by heating limestone and other materials to produce Portland cement.

Cement plant means any facility manufacturing cement by either the wet or dry process.

Clinker means the product of a cement kiln from which finished cement is manufactured by milling and grinding.

Operating day means a 24-hour period beginning at 12:00 midnight during which the kiln produces clinker at any time.

(b) *Applicability.* You are subject to the requirements of this section if you own or operate a new or existing cement kiln that emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing cement kiln with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Long wet kilns: 4.0 lb/ton of clinker;

(2) Long dry kilns: 3.0 lb/ton of clinker;

(3) Preheater kilns: 3.8 lb/ton of clinker;

(4) Precalciner kilns: 2.3 lb/ton of clinker; and

(5) Preheater/Precalciner kilns: 2.8 lb/ton of clinker.

(d) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season. You must calculate and record the 30-operating day rolling average emissions rate of NO_X as the total of all hourly emissions data for a cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-operating day period, using equation 1 to this paragraph (d)(1):

Equation 1 to Paragraph (d)(1)

$$E_{30D} = k\left(\frac{\sum_{i=1}^{N} Ci\ Qi}{P}\right)$$

Where:

E_{30D} = 30 kiln operating day average emissions rate of NO_X, in lbs/ton of clinker.
Ci = Concentration of NO_X for hour i, in ppm.
Qi = Volumetric flow rate of effluent gas for hour i, where Ci and Qi are on the same basis (either wet or dry), in scf/hr.

P = 30 days of clinker production during the same Time period as the NO_X emissions measured, in tons.
k = Conversion factor, 1.194×10^{-7} for NO_X, in lb/scf/ppm.
n = Number of kiln operating hours over 30 kiln operating days.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in terms of lbs/ton of clinker and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (d)(3)(i) through (v) of this section.

(i) You must monitor and record kiln stack exhaust gas flow rate, hourly clinker production rate or kiln feed rate, and kiln stack exhaust temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must determine hourly clinker production by one of two methods:

(A) Install, calibrate, maintain, and operate a permanent weigh scale system to record weight rates of the amount of clinker produced in tons of mass per hour. The system of measuring hourly clinker production must be maintained within ±5 percent accuracy; or

(B) Install, calibrate, maintain, and operate a permanent weigh scale system to measure and record weight rates of the amount of feed to the kiln in tons of mass per hour. The system of measuring feed must be maintained within ±5 percent accuracy. Calculate your hourly clinker production rate using a kiln specific feed-to-clinker ratio based on reconciled clinker production rates determined for accounting purposes and recorded feed rates. This ratio should be updated monthly. Note that if this ratio changes at clinker reconciliation, you must use the new ratio going forward, but you do not have to retroactively change clinker production rates previously estimated.

(C) For each kiln operating hour for which you do not have data on clinker production or the amount of feed to the kiln, use the value from the most recent previous hour for which valid data are available.

(D) If you measure clinker production directly, record the daily clinker production rates; if you measure the kiln feed rates and calculate clinker production, record the daily kiln feed and clinker production rates.

(iii) You must use the kiln stack exhaust gas flow rate, hourly kiln production rate or kiln feed rate, and kiln stack exhaust temperature during the initial performance test and subsequent annual performance tests as indicators of NO_X operating parameters to demonstrate continuous compliance and establish site-specific indicator ranges for these operating parameters.

(iv) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(v) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (e) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(e) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(1) Calendar date;

(2) The average hourly NO_X emissions rates measured or predicted;

(3) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(4) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(7) If a CEMS is used to verify compliance:

(i) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ii) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60; and

(iii) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(8) Operating parameters required under paragraph (d) of this section to demonstrate compliance during the ozone season;

(9) Each fuel type, usage, and heat content; and

(10) Clinker production rates.

(f) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you shall submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit established under paragraph (c) of this section. Excess emissions reports must

be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraph (d) of this section, including record of CEMS data or operating parameters required by paragraph (d) to demonstrate continuous compliance the applicable emissions limits under paragraph (c) of this section.

(g) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (g) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit 100 tons per year or greater as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than December 4, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 52.43 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Iron and Steel Mills and Ferroalloy Manufacturing Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means any reheat furnace meeting the applicability criteria of this section.

Day means a calendar day unless expressly stated to be a business day. In computing any period of time for recordkeeping and reporting purposes where the last day would fall on a Saturday, Sunday, or Federal holiday, the period shall run until the close of business of the next business day.

Low NO_X burner means a burner designed to reduce flame turbulence by the mixing of fuel and air and by establishing fuel-rich zones for initial combustion, thereby reducing the formation of NO_X.

Low-NO_X technology means any post-combustion NO_X control technology capable of reducing NO_X emissions by 40% from baseline emission levels as measured during pre-installation testing.

Operating day means a 24-hour period beginning at 12:00 midnight during which any fuel is combusted at any time in the reheat furnace.

Reheat furnace means a furnace used to heat steel product—including metal ingots, billets, slabs, beams, blooms and other similar products—for the purpose of deformation and rolling.

(b) *Applicability.* The requirements of this section apply to each new or existing reheat furnace at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, does not have low-NO_X burners installed, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing reheat furnace with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions control requirements.* If you are the owner or operator of an affected unit without low-NO_X burners already installed, you must install and operate low-NO_X burners or equivalent alternative low-NO_X technology designed to achieve at least a 40% reduction from baseline NO_X emissions in accordance with the work plan established pursuant to paragraph (d) of this section. You must meet the emissions limit established under paragraph (d) on a 30-day rolling average basis.

(d) *Work plan requirements.* (1) The owner or operator of each affected unit must submit a work plan for each affected unit by August 5, 2024. The work plan must be submitted via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g). Each work plan must include a description of the affected unit and rated production and energy capacities, identification of the low-NO_X burner or alternative low NO_X technology selected, and the phased construction timeframe by which you will design, install, and consistently operate the device. Each work plan shall also include, where applicable, performance test results obtained no more than five years before August 4, 2023, to be used as baseline emissions testing data providing the basis for required emissions reductions. If no such data exist, then the owner or operator must perform pre-installation testing as described in paragraph (e)(3) of this section.

(2) The owner or operator of an affected unit shall design each low-NO_X burner or alternative low-NO_X technology identified in the work plan to achieve NO_X emission reductions by a minimum of 40% from baseline emission levels measured during performance testing that meets the criteria set forth in paragraph (e)(1) of this section, or during pre-installation testing as described in paragraph (e)(3) of this section. Each low-NO_X burner or alternative low-NO_X technology shall be continuously operated during all production periods according to paragraph (c) of this section.

(3) The owner or operator of an affected unit shall establish an emissions limit in the work plan that the affected unit must comply with in accordance with paragraph (c) of this section.

(4) The EPA's action on work plans:

(i) The Administrator will provide via the CEDRI or analogous electronic submission system provided by the EPA notification to the owner or operator of an affected unit if the submitted work plan is complete, that is, whether the request contains sufficient information to make a determination, within 60 calendar days after receipt of the original work plan and within 60 calendar days after receipt of any supplementary information.

(ii) The Administrator will provide notification via the CEDRI or analogous electronic submission system provided by the EPA, which shall be publicly available, to the owner or operator of a decision to approve or intention to disapprove the work plan within 60 calendar days after providing written notification pursuant to paragraph (d)(4)(i) of this section that the submitted work plan is complete.

(iii) Before disapproving a work plan, the Administrator will notify the owner or operator via the CEDRI or analogous electronic submission system provided by the EPA of the Administrator's intention to issue the disapproval, together with:

(A) Notice of the information and findings on which the intended disapproval is based; and

(B) Notice of opportunity for the owner or operator to present in writing, within 15 calendar days after he/she is notified of the intended disapproval, additional information or arguments to the Administrator before further action on the work plan.

(iv) The Administrator's final decision to disapprove a work plan will be via the CEDRI or analogous electronic submission system provided by the EPA and publicly available, and will set forth the specific grounds on which the disapproval is based. The final decision will be made within 60 calendar days after presentation of additional information or argument (if the submitted work plan is complete), or within 60 calendar days after the deadline for the submission of additional information or argument under paragraph (d)(5)(iii)(B) of this section, if no such submission is made.

(v) If the Administrator disapproves the submitted work plan for failure to satisfy the requirements of paragraphs (c) and (d)(1) through (3) of this section, or if the owner or operator of an affected unit fails to submit a work plan by August 5, 2024, the owner or operator will be in violation of this section. Each day that the affected unit operates following such disapproval or failure to submit shall constitute a violation.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season.

(2) If you are the owner or operator of an affected unit and are operating a NO_X continuous emissions monitoring system (CEMS) that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in form of the emissions limit established in the work plan and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits established in the work plan.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (e)(3)(i) through (iv) of this section.

(i) You must monitor and record stack exhaust gas flow rate and temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must use the stack exhaust gas flow rate and temperature during the initial performance test and subsequent annual performance tests to establish a site-specific indicator for these operating parameters.

(iii) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(iv) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (f) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(1) Calendar date;

(2) The average hourly NO_X emissions rates measured or predicted;

(3) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(4) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(5) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(6) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(7) If a CEMS is used to verify compliance:

(i) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ii) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60; and

(iii) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(8) Operating parameters required under paragraph (d) of this section to demonstrate compliance during the ozone season; and

(9) Each fuel type, usage, and heat content.

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you shall submit a final report via the CEDRI or analogous electronic submission system provided by the EPA, by no later than March 30, 2026, certifying that installation of each selected control device has been completed. You shall include in the report the dates of final construction and relevant performance testing, where applicable, demonstrating compliance with the selected emission limits pursuant to paragraphs (c) and (d) of this section.

(2) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(3) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit established under paragraphs (c) and (d) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(4) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraphs (e) and (f) of this section, including record of CEMS data or operating parameters required by paragraph (e) to demonstrate compliance the applicable emissions limits established under paragraphs (c) and (d) of this section.

(h) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (h) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit 100 tons per year or more of NO_X as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than December 4, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 52.44 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Glass and Glass Product Manufacturing Industry?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected units means a glass manufacturing furnace meeting the applicability criteria of this section.

Borosilicate recipe means glass product composition of the following approximate ranges of weight proportions: 60 to 80 percent silicon dioxide, 4 to 10 percent total R_2O (*e.g.,* Na_2O and K_2O), 5 to 35 percent boric oxides, and 0 to 13 percent other oxides.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in Standard Industrial Classification (SIC) 3221 (SIC 3221).

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in SIC 3211.

Glass melting furnace means a unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass. The unit includes foundations, superstructure and retaining walls, raw material charger systems, heat exchangers, melter cooling system, exhaust system, refractory brick work, fuel supply and electrical boosting equipment, integral control systems and instrumentation, and appendages for conditioning and distributing molten glass to forming apparatuses. The forming apparatuses, including the float bath used in flat glass manufacturing and flow channels in wool fiberglass and textile fiberglass manufacturing, are not considered part of the glass melting furnace.

Glass produced means the weight of the glass pulled from the glass melting furnace.

Idling means the operation of a glass melting furnace at less than 25% of the permitted production capacity or fuel use capacity as stated in the operating permit.

Lead recipe means glass product composition of the following ranges of weight proportions: 50 to 60 percent silicon dioxide, 18 to 35 percent lead oxides, 5 to 20 percent total R_2O (*e.g.,* Na_2O and K_2O), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), 0 to 15 percent total RO (*e.g.,* CaO, MgO), other than lead oxide, and 5 to 10 percent other oxides.

Operating day means a 24-hr period beginning at 12:00 midnight during which the furnace combusts fuel at any time but excludes any period of startup, shutdown, or idling during which the affected unit complies with the requirements in paragraphs (d) through (f) of this section, as applicable.

Pressed and blown glass means glass which is pressed, blown, or both, including textile fiberglass, noncontinuous flat glass, noncontainer glass, and other products listed in SIC 3229. It is separated into: Glass of borosilicate recipe, Glass of soda-lime and lead recipes, and Glass of opal, fluoride, and other recipes.

Raw material means minerals, such as silica sand, limestone, and dolomite; inorganic chemical compounds, such as soda ash (sodium carbonate), salt cake (sodium sulfate), and potash (potassium carbonate); metal oxides and other metal-based compounds, such as lead oxide, chromium oxide, and sodium antimonate; metal ores, such as chromite and pyrolusite; and other substances that are intentionally added to a glass manufacturing batch and melted in a glass melting furnace to produce glass. Metals that are naturally-occurring trace constituents or contaminants of other substances are not considered to be raw materials.

Shutdown means the period of time during which a glass melting furnace is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to a cold or ambient temperature as the fuel supply is turned off.

Soda-lime recipe means glass product composition of the following ranges of weight proportions: 60 to 75 percent silicon dioxide, 10 to 17 percent total R_2O (*e.g.,* Na_2O and K_2O), 8 to 20 percent total RO but not to include any PbO (*e.g.,* CaO, and MgO), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), and 1 to 5 percent other oxides.

Startup means the period of time, after initial construction or a furnace rebuild, during which a glass melting furnace is heated to operating temperatures by the primary furnace combustion system, and systems and instrumentation are brought to stabilization.

Textile fiberglass means fibrous glass in the form of continuous strands having uniform thickness.

Wool fiberglass means fibrous glass of random texture, including accoustical board and tile (mineral wool), fiberglass insulation, glass wool, insulation (rock wool, fiberglass, slag, and silicia minerals), and mineral wool roofing mats.

(b) *Applicability.* You are subject to the requirements under this section if you own or operate a new or existing glass manufacturing furnace that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). Any existing glass manufacturing furnace with a potential to emit of 100 tons per year or more of NO_X on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NO_X.

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the emissions limitations in paragraphs (c)(1) and (2) of this section on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter. For the 2026 ozone season, the emissions limitations in paragraphs (c)(1) and (2) do not apply during shutdown and idling if the affected unit complies with the requirements in paragraphs (e) and (f) of this section, as applicable. For the 2027 and subsequent ozone seasons, the emissions limitations in paragraphs (c)(1) and (2) do not apply during startup, shutdown, and idling, if the affected unit complies with the requirements in paragraphs (d) through (f) of this section, as applicable.

(1) Container glass, pressed/blown glass, or fiberglass manufacturing furnace: 4.0 lb/ton of glass; and

(2) Flat glass manufacturing furnace: 7.0 lb/ton of glass.

(d) *Startup requirements.* (1) If you are the owner or operator of an affected unit, you shall submit via the CEDRI or analogous electronic submission system provided by the EPA, no later than 30 days prior to the anticipated date of startup, the following information to assure proper operation of the furnace:

(i) A detailed list of activities to be performed during startup and explanations to support the length of time needed to complete each activity.

(ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the startup period.

(iii) Identification of the control technologies or strategies to be utilized.

(iv) A description of the physical conditions present during startup periods that prevent the controls from being effective.

(v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

(2) The length of startup following activation of the primary furnace combustion system may not exceed:

(i) Seventy days for a container, pressed or blown glass furnace;

(ii) Forty days for a fiberglass furnace; and

(iii) One hundred and four days for a flat glass furnace and for all other glass melting furnaces not covered under paragraphs (d)(2)(i) and (ii) of this section.

(3) During the startup period, the owner or operator of an affected unit shall maintain the stoichiometric ratio of the primary furnace combustion system so as not to exceed 5 percent excess oxygen, as calculated from the actual fuel and oxidant flow measurements for combustion in the affected unit.

(4) The owner or operator of an affected unit shall place the emissions control system in operation as soon as technologically feasible during startup to minimize emissions.

(e) *Shutdown requirements.* (1) If you are the owner or operator of an affected unit, you shall submit via the CEDRI or analogous electronic submission system provided by the EPA to the Administrator, no later than 30 days prior to the anticipated date of shutdown, the following information to assure proper operation of the furnace:

(i) A detailed list of activities to be performed during shutdown and explanations to support the length of time needed to complete each activity.

(ii) A description of the material process flow rates, system operating parameters, and other information that the owner or operator shall monitor and record during the shutdown period.

(iii) Identification of the control technologies or strategies to be utilized.

(iv) A description of the physical conditions present during shutdown periods that prevent the controls from being effective.

(v) A reasonably precise estimate as to when physical conditions will have reached a state that allows for the effective control of emissions.

(2) The duration of a shutdown, as measured from the time the furnace operations drop below 25% of the permitted production capacity or fuel use capacity to when all emissions from the furnace cease, may not exceed 20 days.

(3) If you are the owner or operator of an affected unit, you shall operate the emissions control system whenever technologically feasible during shutdown to minimize emissions.

(f) *Idling requirements.* (1) If you are the owner or operator of an affected unit, you shall operate the emissions control system whenever technologically feasible during idling to minimize emissions.

(2) If you are the owner or operator of an affected unit, your NO_X emissions during idling may not exceed the amount calculated using the following equation: Pounds per day emissions limit of NO_X = (Applicable NO_X emissions limit specified in paragraph (c) of this section expressed in pounds per ton of glass produced) × (Furnace permitted production capacity in tons of glass produced per day).

(3) To demonstrate compliance with the alternative daily NO_X emissions limit identified in paragraph (f)(2) of this section during periods of idling, the owners or operators of an affected unit shall maintain records consistent with paragraph (h)(3) of this section.

(g) *Testing and monitoring requirements.* (1) If you own or operate an affected unit subject to the NO_X emissions limits under paragraph (c) of this section you must conduct performance tests, on an annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, appendix A–4, any alternative test method approved by the EPA as of June 5, 2023, under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at the EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by the EPA through notice-and-comment rulemaking. The annual performance test does not have to be performed during the ozone season. Owners or operators of affected units must calculate and record the 30-day rolling average emissions rate of NO_X as the total of all hourly emissions data for an affected unit in the preceding 30 days, divided by the total tons of glass produced in that affected unit during the same 30-day period. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass produced during the performance test.

The rate of glass produced is defined as the weight of glass pulled from the affected unit during the performance test divided by the number of hours taken to perform the performance test.

(2) If you are the owner or operator of an affected unit subject to the NO_X emissions limits under paragraph (c)(1) of this section and are operating a NO_X CEMS that monitors NO_X emissions from the affected unit, you may use the CEMS data in lieu of the annual performance tests and parametric monitoring required under this section. You must meet the following requirements for using CEMS to monitor NO_X emissions:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2).

(ii) The CEMS shall be operated and data recorded during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(iii) The 1-hour average NO_X emissions rates measured by the CEMS shall be expressed in terms of lbs/ton of glass and shall be used to calculate the average emissions rates to demonstrate compliance with the applicable emissions limits in this section.

(iv) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(v) When NO_X emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emissions data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(3) If you are the owner or operator of an affected unit not operating NO_X CEMS, you must conduct an initial performance test before the 2026 ozone season to establish appropriate indicator ranges for operating parameters and continuously monitor those operator parameters consistent with the requirements of paragraphs (g)(3)(i) through (iv) of this section.

(i) You must monitor and record stack exhaust gas flow rate, hourly glass production, and stack exhaust gas temperature during the initial performance test and subsequent annual performance tests to demonstrate continuous compliance with your NO_X emissions limits.

(ii) You must use the stack exhaust gas flow rate, hourly glass production, and stack exhaust gas temperature during the initial performance test and subsequent annual performance tests as NO_X CEMS indicators to demonstrate continuous compliance and establish a site-specific indicator ranges for these operating parameters.

(iii) You must repeat the performance test annually to reassess and adjust the site-specific operating parameter indicator ranges in accordance with the results of the performance test.

(iv) You must report and include your ongoing site-specific operating parameter data in the annual reports required under paragraph (h) of this section and semi-annual title V monitoring reports to the relevant permitting authority.

(4) If you are the owner or operator of an affected unit seeking to comply with the requirements for startup under paragraph (d) of this section or shutdown under paragraph (e) of this section in lieu of the applicable emissions limit under paragraph (c) of this section, you must monitor material process flow rates, fuel throughput, oxidant flow rate, and the selected system operating parameters in accordance with paragraphs (d)(1)(ii) and (e)(1)(ii) of this section.

(h) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, you shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emissions rates measured or predicted;

(iii) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emissions rates are in excess of the applicable site-specific NO_X emissions limit with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(vii) If a CEMS is used to verify compliance:

(A) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(B) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60; and

(C) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F;

(D) Operating parameters required under paragraph (g) to demonstrate compliance during the ozone season;

(viii) Each fuel type, usage, and heat content; and

(ix) Glass production rate.

(2) If you are the owner or operator of an affected unit, you shall maintain all records necessary to demonstrate compliance with the startup and shutdown requirements in paragraphs (d) and (e) of this section, including but not limited to records of material process flow rates, system operating parameters, the duration of each startup and shutdown period, fuel throughput, oxidant flow rate, and any additional records necessary to determine whether the stoichiometric ratio of the primary furnace combustion system exceeded 5 percent excess oxygen during startup.

(3) If you are the owner or operator of an affected unit, you shall maintain records of daily NO_X emissions in pounds per day for purposes of determining compliance with the applicable emissions limit for idling periods under paragraph (f)(2) of this section. Each owner or operator shall also record the duration of each idling period.

(i) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you own or operate an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include records all records required by paragraph (g) of this section, including record of CEMS data or operating parameters to demonstrate continuous compliance the applicable emissions limits under paragraphs (c) of this section.

(j) *Initial notification requirements for existing affected units.* (1) The requirements of this paragraph (j) apply to the owner or operator of an existing affected unit.

(2) The owner or operator of an existing affected unit that emits or has a potential to emit greater than 100 tons per year or greater as of August 4, 2023, shall notify the Administrator via the CEDRI or analogous electronic submission system provided by the EPA that the unit is subject to this section. The notification, which shall be submitted not later than June 23, 2023, shall be submitted in PDF format to the EPA via CEDRI, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The notification shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (*i.e.,* physical location) of the affected unit;

(iii) An identification of the relevant standard, or other requirement, that is the basis for the notification and the unit's compliance date; and

(iv) A brief description of the nature, size, design, and method of operation of the facility and an identification of the types of emissions points (units) within the facility subject to the relevant standard.

§ 52.45 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, the Pulp, Paper, and Paperboard Mills Industries, Metal Ore Mining, and the Iron and Steel and Ferroalloy Manufacturing Industries?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given to them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an industrial boiler meeting the applicability criteria of this section.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled.

Coal means ''coal'' as defined in 40 CFR 60.41b.

Distillate oil means ''distillate oil'' as defined in 40 CFR 60.41b.

Maximum heat input capacity means means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Natural gas means ''natural gas'' as defined in 40 CFR 60.41.

Operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

Residual oil means ''residual oil'' as defined in 40 CFR 60.41c.

(b) *Applicability.* (1) The requirements of this section apply to each new or existing boiler with a design capacity of 100 mmBtu/hr or greater that receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels in the previous ozone season, is located at sources that are within the Basic Chemical Manufacturing industry, the Petroleum and Coal Products Manufacturing industry, the Pulp, Paper, and Paperboard industry, the Metal Ore Mining industry, and the Iron and Steel and Ferroalloys Manufacturing industry and which is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s). The requirements of this section do not apply to an emissions unit that meets the requirements for a low-use exemption as provided in paragraph (b)(2) of this section.

(2) If you are the owner or operator of a boiler meeting the applicability criteria of paragraph (b)(1) of this section that operates less than 10% per year on an hourly basis, based on the three most recent years of use and no more than 20% in any one of the three years, you are exempt from meeting the emissions limits of this section and are only subject to the recordkeeping and reporting requirements of paragraph (f)(2) of this section.

(i) If you are the owner or operator of an affected unit that exceeds the 10% per year hour of operation over three years or the 20% hours of operation per year criteria, you can no longer comply via the low-use exemption provisions and must meet the applicable emissions limits and other applicable provisions as soon as possible but not later than one year from the date eligibility as a low-use boiler was negated by exceedance of the low-use boiler criteria.

(ii) [Reserved]

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) Coal-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(2) Residual oil-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(3) Distillate oil-fired industrial boilers: 0.12 lbs NO_X/mmBtu;

(4) Natural gas-fired industrial boilers: 0.08 lbs NO_X/mmBtu; and

(5) Boilers using combinations of fuels listed in paragraphs (c)(1) through (4) of this section: such units shall comply with a NO_X emissions limit derived by summing the products of each fuel's heat input and respective emissions limit and dividing by the sum of the heat input contributed by each fuel.

(d) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit, you shall conduct an initial compliance test as described in 40 CFR 60.8 using the continuous system for monitoring NO_X specified by EPA Test Method 7E of 40 CFR part 60, appendix A–4, to determine compliance with the emissions limits for NO_X identified in paragraph (c) of this section. In lieu of the timing of the compliance test described in 40 CFR 60.8(a), you shall conduct the test within 90 days from the installation of the pollution control equipment used to comply with the NO_X emissions limits in paragraph (c) of this section and no later than May 1, 2026.

(i) For the initial compliance test, you shall monitor NO_X emissions from the affected unit for 30 successive operating days and the 30-day average emissions rate will be used to determine compliance with the NO_X emissions limits in paragraph (c) of this section. You shall calculate the 30-day average emission rate as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

(ii) You are not required to conduct an initial compliance test if the affected unit is subject to a pre-existing, federally enforceable requirement to monitor its NO_X emissions using a

CEMS in accordance with 40 CFR 60.13 or 40 CFR part 75.

(2) If you are the owner or operator of an affected unit with a heat input capacity of 250 mmBTU/hr or greater, you are subject to the following monitoring requirements:

(i) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2), unless the Administrator has approved a request from you to use an alternative monitoring technique under paragraph (d)(2)(vii) of this section. If you have previously installed a NO_X emissions rate CEMS to meet the requirements of 40 CFR 60.13 or 40 CFR part 75 and continue to meet the ongoing requirements of 40 CFR 60.13 or 40 CFR part 75, that CEMS may be used to meet the monitoring requirements of this section.

(ii) You shall operate the CEMS and record data during all periods of operation during the ozone season of the affected unit except for CEMS breakdowns and repairs. You shall record data during calibration checks and zero and span adjustments.

(iii) You shall express the 1-hour average NO_X emissions rates measured by the CEMS in terms of lbs/mmBtu heat input and shall be used to calculate the average emissions rates under paragraph (c) of this section.

(iv) Following the date on which the initial compliance test is completed, you shall determine compliance with the applicable NO_X emissions limit in paragraph (c) of this section during the ozone season on a continuous basis using a 30-day rolling average emissions rate unless you monitor emissions by means of an alternative monitoring procedure approved pursuant to paragraph (d)(2)(vii) of this section. You shall calculate a new 30-day rolling average emissions rate for each operating day as the average of all the hourly NO_X emissions data for the preceding 30 operating days.

(v) You shall follow the procedures under 40 CFR 60.13 for installation, evaluation, and operation of the continuous monitoring systems. Additionally, you shall use a span value of 1000 ppm NO_X for affected units combusting coal and span value of 500 ppm NO_X for units combusting oil or gas. As an alternative to meeting these span values, you may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to 40 CFR part 75.

(vi) When you are unable to obtain NO_X emissions data because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, you will obtain emissions data by using standby monitoring systems, Method 7 of 40 CFR part 60, appendix A–4, Method 7A of 40 CFR part 60, appendix A–4, or other approved reference methods to provide emissions data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(vii) You may delay installing a CEMS for NO_X until after the initial performance test has been conducted. If you demonstrate during the performance test that emissions of NO_X are less than 70 percent of the applicable emissions limit in paragraph (c) of this section, you are not required to install a CEMS for measuring NO_X. If you demonstrate your affected unit emits less than 70 percent of the applicable emissions limit chooses to not install a CEMS, you must submit a written request to the Administrator that documents the results of the initial performance test and includes an alternative monitoring procedure that will be used to track compliance with the applicable NO_X emissions limit(s) in paragraph (c) of this section. The Administrator may consider the request and, following public notice and comment, may approve the alternative monitoring procedure with or without revision, or disapprove the request. Upon receipt of a disapproved request, you will have one year to install a CEMS.

(3) If you are the owner or operator of an affected unit with a heat input capacity less than 250 mmBTU/hr, you must monitor NO_X emission via the requirements of paragraph (e)(1) of this section or you must monitor NO_X emissions by conducting an annual test in conjunction with the implementation of a monitoring plan meeting the following requirements:

(i) You must conduct an initial performance test over a minimum of 24 consecutive steam generating unit operating hours at maximum heat input capacity to demonstrate compliance with the NO_X emission standards under paragraph (c) of this section using Method 7, 7A, or 7E of appendix A–4 to 40 CFR part 60, Method 320 of appendix A to 40 CFR part 63, or other approved reference methods.

(ii) You must conduct annual performance tests once per calendar year to demonstrate compliance with the NO_X emission standards under paragraph (c) of this section over a minimum of 3 consecutive steam generating unit operating hours at maximum heat input capacity using Method 7, 7A, or 7E of appendix A–4 to 40 CFR part 60, Method 320 of appendix A to 40 CFR part 63, or other approved reference methods. The annual performance test must be conducted before the affected units operates more than 400 hours in a given year.

(iii) You must develop and comply with a monitoring plan that relates the operational parameters to emissions of the affected unit. The owner or operator of each affected unit shall develop a monitoring plan that identifies the operating conditions of the affected unit to be monitored and the records to be maintained in order to reliably predict NO_X emissions and determine compliance with the applicable emissions limits of this section on a continuous basis. You shall include the following information in the plan:

(A) You shall identify the specific operating parameters to be monitored and the relationship between these operating parameters and the applicable NO_X emission rates. Operating parameters of the affected unit include, but are not limited to, the degree of staged combustion (*i.e.,* the ratio of primary air to secondary and/or tertiary air) and the level of excess air (*i.e.,* flue gas O_2 level).

(B) You shall include the data and information used to identify the relationship between NO_X emission rates and these operating conditions.

(C) *You shall identify:* how these operating parameters, including steam generating unit load, will be monitored on an hourly basis during periods of operation of the affected unit; the quality assurance procedures or practices that will be employed to ensure that the data generated by monitoring these operating parameters will be representative and accurate; and the type and format of the records of these operating parameters, including steam generating unit load, that you will maintain.

(4) You shall submit the monitoring plan to the EPA via the CEDRI reporting system, and request that the relevant permitting agency incorporate the monitoring plan into the facility's title V permit.

(e) *Recordkeeping requirements.* (1) If you are the owner or operator of an affected unit, which is not a low-use boiler, you shall maintain records of the following information for each day the affected unit operates during the ozone season:

(i) Calendar date;

(ii) The average hourly NO_X emissions rates (expressed as lbs NO_2/mmBtu heat input) measured or predicted;

(iii) The 30-day average NO_X emissions rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emissions rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day rolling average NO_X emissions rates are in excess of the applicable NO_X emissions limit in paragraph (c) of this section with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emissions data have been excluded from the calculation of average emissions rates and the reasons for excluding data;

(vii) Identification of ''F'' factor used for calculations, method of determination, and type of fuel combusted;

(viii) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ix) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B to 40 CFR part 60;

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F; and

(xi) The type and amounts of each fuel combusted.

(2) If you are the owner or operator of an affected unit complying as a low-use boiler, you must maintain the following records consistent with the requirements of § 52.40(g):

(i) Identification and location of the boiler;

(ii) Nameplate capacity;

(iii) The fuel or fuels used by the boiler;

(iv) For each operating day, the type and amount of fuel combusted, and the date and total number of hours of operation; and

(v) the annual hours of operation for each of the prior 3 years, and the 3-year average hours or operation.

(f) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you are required to submit excess emissions reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emissions rate, as determined under paragraph (e)(1)(iii) of this section, that exceeds the applicable emissions limit in paragraph (c) of this section. Excess emissions reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(3) If you are the owner or operator an affected unit subject to the continuous monitoring requirements for NO_X under paragraph (d) of this section, you shall submit reports containing the information recorded under paragraph (d) of this section as described in paragraph (e)(1) of this section. You shall submit compliance reports for continuous monitoring in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section following the procedures specified in § 52.40(g).

(4) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g).

§ 52.46 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from Municipal Waste Combustors?

(a) *Definitions.* All terms not defined in this paragraph (a) shall have the meaning given them in the Act and in subpart A of 40 CFR part 60.

Affected unit means a municipal waste combustor meeting the applicability criteria of this section.

Chief facility operator means the person in direct charge and control of the operation of a municipal waste combustor and who is responsible for daily onsite supervision, technical direction, management, and overall performance of the facility.

Mass burn refractory municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a refractory wall furnace. Unless otherwise specified, this includes combustors with a cylindrical rotary refractory wall furnace.

Mass burn rotary waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a cylindrical rotary waterwall furnace or on a tumbling-tile grate.

Mass burn waterwall municipal waste combustor means a field-erected combustor that combusts municipal solid waste in a waterwall furnace.

Municipal waste combustor, MWC, or *municipal waste combustor unit* means:

(i) Means any setting or equipment that combusts solid, liquid, or gasified MSW including, but not limited to, field-erected incinerators (with or without heat recovery), modular incinerators (starved-air or excess-air), boilers (*i.e.,* steam-generating units), furnaces (whether suspension-fired, grate-fired, mass-fired, air curtain incinerators, or fluidized bed-fired), and pyrolysis/combustion units. Municipal waste combustors do not include pyrolysis/combustion units located at plastics/rubber recycling units. Municipal waste combustors do not include internal combustion engines, gas turbines, or other combustion devices that combust landfill gases collected by landfill gas collection systems.

(ii) The boundaries of a MWC are defined as follows. The MWC unit includes, but is not limited to, the MSW fuel feed system, grate system, flue gas system, bottom ash system, and the combustor water system. The MWC boundary starts at the MSW pit or hopper and extends through:

(A) The combustor flue gas system, which ends immediately following the heat recovery equipment or, if there is no heat recovery equipment, immediately following the combustion chamber;

(B) The combustor bottom ash system, which ends at the truck loading station or similar ash handling equipment that transfer the ash to final disposal, including all ash handling systems that are connected to the bottom ash handling system; and

(C) The combustor water system, which starts at the feed water pump and ends at the piping exiting the steam drum or superheater.

(iii) The MWC unit does not include air pollution control equipment, the stack, water treatment equipment, or the turbine generator set.

Municipal waste combustor unit capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under paragraph (e)(4) of this section.

Shift supervisor means the person who is in direct charge and control of the operation of a municipal waste combustor and who is responsible for onsite supervision, technical direction, management, and overall performance of the facility during an assigned shift.

(b) *Applicability.* The requirements of this section apply to each new or existing municipal waste combustor unit with a combustion capacity greater than 250 tons per day (225 megagrams per day) of municipal solid waste and which is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations.* If you are the owner or operator of an affected unit, you must meet the following emissions limitations at all times, except during startup and shutdown, on a 30-day rolling average basis during the 2026 ozone season and in each ozone season thereafter:

(1) 110 ppmvd at 7 percent oxygen on a 24-hour block averaging period; and

(2) 105 ppmvd at 7 percent oxygen on a 30-day rolling averaging period.

(d) *Startup and shutdown requirements.* If you are the owner or operator of an affected unit, you must comply with the following requirements during startup and shutdown:

(1) During periods of startup and shutdown, you shall meet the following emissions limits at stack oxygen content:

(i) 110 ppmvd at stack oxygen content on a 24-hour block averaging period; and

(ii) 105 ppmvd at stack oxygen content on a 30-day rolling averaging period.

(2) Duration of startup and shutdown, periods are limited to 3 hours per occurrence.

(3) The startup period commences when the affected unit begins the continuous burning of municipal solid waste and does not include any warmup period when the affected unit is combusting fossil fuel or other nonmunicipal solid waste fuel, and no municipal solid waste is being fed to the combustor.

(4) Continuous burning is the continuous, semicontinuous, or batch feeding of municipal solid waste for purposes of waste disposal, energy production, or providing heat to the combustion system in preparation for waste disposal or energy production. The use of municipal solid waste solely to provide thermal protection of the grate or hearth during the startup period when municipal solid waste is not being fed to the grate is not considered to be continuous burning.

(5) The owner and operator of an affected unit shall minimize NO_X emissions by operating and optimizing the use of all installed pollution control technology and combustion controls consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices, and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)) for such equipment and the unit at all times the unit is in operation.

(e) *Testing and monitoring requirements.* (1) If you are the owner or operator of an affected unit, you shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring the oxygen or carbon dioxide content of the flue gas at each location where NO_X are monitored and record the output of the system. You shall comply with the following test procedures and test methods:

(i) You shall use a span value of 25 percent oxygen for the oxygen monitor or 20 percent carbon dioxide for the carbon dioxide monitor;

(ii) You shall install, evaluate, and operate the CEMS in accordance with 40 CFR 60.13;

(iii) You shall complete the initial performance evaluation no later than 180 days after the date of initial startup of the affected unit, as specified under 40 CFR 60.8;

(iv) You shall operate the monitor in conformance with Performance Specification 3 in 40 CFR part 60, appendix B, except for section 2.3 (relative accuracy requirement);

(v) You shall operate the monitor in accordance with the quality assurance procedures of 40 CFR part 60, appendix F, except for section 5.1.1 (relative accuracy test audit); and

(vi) If you select carbon dioxide for use in diluent corrections, you shall establish the relationship between oxygen and carbon dioxide levels during the initial performance test according to the following procedures and methods:

(A) This relationship may be reestablished during performance compliance tests; and

(B) You shall submit the relationship between carbon dioxide and oxygen concentrations to the EPA as part of the initial performance test report and as part of the annual test report if the relationship is reestablished during the annual performance test.

(2) If you are the owner or operator of an affected unit, you shall use the following procedures and test methods to determine compliance with the NO_X emission limits in paragraph (c) of this section:

(i) If you are not already operating a CEMS in accordance with 40 CFR 60.13, you shall conduct an initial performance test for nitrogen oxides consistent with 40 CFR 60.8.

(ii) You shall install and operate the NO_X CEMS according to Performance Specification 2 in 40 CFR part 60, appendix B, and shall follow the requirements of 40 CFR 60.58b(h)(10).

(iii) Quarterly accuracy determinations and daily calibration drift tests for the CEMS shall be performed in accordance with Procedure 1 in 40 CFR part 60, appendix F.

(iv) When NO_X continuous emissions data are not obtained because of CEMS breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained using other monitoring systems as approved by the EPA or EPA Reference Method 19 in 40 CFR part 60, appendix A–7, to provide, as necessary, valid emissions data for a minimum of 90 percent of the hours per calendar quarter and 95 percent of the hours per calendar year the unit is operated and combusting municipal solid waste.

(v) You shall use EPA Reference Method 19, section 4.1, in 40 CFR part 60, appendix A–7, for determining the daily arithmetic average NO_X emissions concentration.

(A) You may request that compliance with the NO_X emissions limit be determined using carbon dioxide measurements corrected to an equivalent of 7 percent oxygen. The relationship between oxygen and carbon dioxide levels for the affected unit shall be established as specified in paragraph (e)(1)(vi) of this section.

(B) [Reserved]

(vi) At a minimum, you shall obtain valid CEMS hourly averages for 90 percent of the operating hours per calendar quarter and for 95 percent of the operating hours per calendar year that the affected unit is combusting municipal solid waste:

(A) At least 2 data points per hour shall be used to calculate each 1-hour arithmetic average.

(B) Each NO_X 1-hour arithmetic average shall be corrected to 7 percent oxygen on an hourly basis using the 1-hour arithmetic average of the oxygen (or carbon dioxide) continuous emissions monitoring system data.

(vii) The 1-hour arithmetic averages section shall be expressed in parts per million by volume (dry basis) and used to calculate the 24-hour daily arithmetic average concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under 40 CFR 60.13(e)(2).

(viii) All valid CEMS data must be used in calculating emissions averages even if the minimum CEMS data requirements of paragraph (e)(2)(iv) of this section are not met.

(ix) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the CEMS. The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the municipal waste combustor unit.

(3) If you are the owner or operator of an affected unit, you must determine compliance with the startup and shutdown requirements of paragraph (d) of this section by following the requirements in paragraphs (e)(3)(i) and (ii) of this section:

(i) You can measure CEMS data at stack oxygen content. You can dismiss or exclude CEMS data from compliance calculations, but you shall record and report CEMS data in accordance with the provisions of 40 CFR 60.59b(d)(7).

(ii) You shall determine compliance with the NO_X mass loading emissions limitation for periods of startup and shutdown by calculating the 24-hour average of all hourly average NO_X emissions concentrations from continuous emissions monitoring systems.

(A) You shall perform this calculations using stack flow rates derived from flow monitors, for all the hours during the 3-hour startup or shutdown period and the remaining 21 hours of the 24-hour period.

(B) [Reserved]

(4) If you are the owner or operator of an affected unit, you shall calculate municipal waste combustor unit capacity using the following procedures:

(i) For municipal waste combustor units capable of combusting municipal solid waste continuously for a 24-hour period, municipal waste combustor unit capacity shall be calculated based on 24 hours of operation at the maximum charging rate. The maximum charging rate shall be determined as specified in paragraphs (e)(4)(i)(A) and (B) of this section as applicable.

(A) For combustors that are designed based on heat capacity, the maximum charging rate shall be calculated based on the maximum design heat input capacity of the unit and a heating value of 12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and a heating value of 10,500 kilojoules per kilogram for combustors firing municipal solid waste that is not refuse-derived fuel.

(B) For combustors that are not designed based on heat capacity, the maximum charging rate shall be the maximum design charging rate.

(ii) For batch feed municipal waste combustor units, municipal waste combustor unit capacity shall be calculated as the maximum design amount of municipal solid waste that can be charged per batch multiplied by the maximum number of batches that could be processed in a 24-hour period. The maximum number of batches that could be processed in a 24-hour period is calculated as 24 hours divided by the design number of hours required to process one batch of municipal solid waste, and may include fractional batches (*e.g.,* if one batch requires 16 hours, then 24/16, or 1.5 batches, could be combusted in a 24-hour period). For batch combustors that are designed based on heat capacity, the design heating value of 12,800 kilojoules per kilogram for combustors firing refuse-derived fuel and a heating value of 10,500 kilojoules per kilogram for combustors firing municipal solid waste that is not refuse-derived fuel shall be used in calculating the municipal waste combustor unit capacity in megagrams per day of municipal solid waste.

(f) *Recordkeeping requirements.* If you are the owner or operator of an affected unit, you shall maintain records of the following information, as applicable, for each affected unit consistent with the requirements of § 52.40(g).

(1) The calendar date of each record.

(2) The emissions concentrations and parameters measured using continuous monitoring systems.

(i) All 1-hour average NO_X emissions concentrations.

(ii) The average concentrations and percent reductions, as applicable, including all 24-hour daily arithmetic average NO_X emissions concentrations.

(3) Identification of the calendar dates and times (hours) for which valid hourly NO_X emissions, including reasons for not obtaining the data and a description of corrective actions taken.

(4) Identification of each occurrence that NO_X emissions data, or operational data (*i.e.,* unit load) have been excluded from the calculation of average emissions concentrations or parameters, and the reasons for excluding the data.

(5) The results of daily drift tests and quarterly accuracy determinations for CEMS, as required under 40 CFR part 60, appendix F, Procedure 1.

(6) The following records:

(i) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have been provisionally certified by the American Society of Mechanical Engineers or an equivalent State-approved certification program as required by 40 CFR 60.54b(a) including the dates of initial and renewal certifications and documentation of current certification;

(ii) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have been fully certified by the American Society of Mechanical Engineers or an equivalent State-approved certification program as required by 40 CFR 60.54b(b) including the dates of initial and renewal certifications and documentation of current certification;

(iii) Records showing the names of the municipal waste combustor chief facility operator, shift supervisors, and control room operators who have completed the EPA municipal waste combustor operator training course or a State-approved equivalent course as required by 40 CFR 60.54b(d) including documentation of training completion; and

(iv) Records of when a certified operator is temporarily off site. Include two main items:

(A) If the certified chief facility operator and certified shift supervisor are off site for more than 12 hours, but for 2 weeks or less, and no other certified operator is on site, record the dates that the certified chief facility operator and certified shift supervisor were off site.

(B) When all certified chief facility operators and certified shift supervisors are off site for more than 2 weeks and no other certified operator is on site, keep records of four items:

(*1*) Time of day that all certified persons are off site.

(*2*) The conditions that cause those people to be off site.

(*3*) The corrective actions taken by the owner or operator of the affected unit to ensure a certified chief facility operator or certified shift supervisor is on site as soon as practicable.

(*4*) Copies of the reports submitted every 4 weeks that summarize the actions taken by the owner or operator of the affected unit to ensure that a certified chief facility operator or certified shift supervisor will be on site as soon as practicable.

(7) Records showing the names of persons who have completed a review of the operating manual as required by 40 CFR 60.54b(f) including the date of the initial review and subsequent annual reviews.

(8) Records of steps taken to minimize emissions during startup and shutdown as required by paragraph (d)(5) of this section.

(g) *Reporting requirements.* (1) If you are the owner or operator of an affected unit, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in § 52.40(g) within 60 days after the date of completing each performance test required by this section.

(2) If you are the owner or operator of an affected unit, you shall submit an annual report in PDF format to the EPA by January 30th of each year via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. Annual reports shall be submitted following the procedures in § 52.40(g). The report shall include all information required by paragraph (e) of this section, including CEMS data to demonstrate compliance with the applicable emissions limits under paragraph (c) of this section.

Subpart B—Alabama

■ 5. Amend § 52.54 by revising paragraphs (b)(2) and (3) and adding paragraphs (b)(4) and (5) to read as follows:

§ 52.54 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(3) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

Subpart E—Arkansas

■ 6. Amend § 52.184 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2):

■ i. Removing "2017 and each subsequent year" and adding in its place "2017 through 2022"; and

■ ii. Removing the second sentence;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Arkansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Arkansas' SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Arkansas and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart F—California

■ 7. Add § 52.284 to read as follows:

§ 52.284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner and operator of each source located in the State of California and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart O—Illinois

■ 8. Amend § 52.731 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.731 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Illinois and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart P—Indiana

■ 9. Amend § 52.789 by:
■ a. In paragraph (b)(2), removing ''(b)(2)(iv), except'' and adding in its place ''(b)(2)(ii), except'';
■ b. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ c. Adding paragraph (c).

The addition reads as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Indiana and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart S—Kentucky

■ 10. Amend § 52.940 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Kentucky and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart T—Louisiana

■ 11. Amend § 52.984 by:
■ a. In paragraph (d)(3), revising the second and third sentences;
■ b. Revising paragraph (d)(4);
■ c. In paragraph (d)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (e).

The revision and addition read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Louisiana's SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(e) The owner and operator of each source located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart V—Maryland

■ 12. Amend § 52.1084 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1084 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Maryland

and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart X—Michigan

■ 13. Amend § 52.1186 by:

■ a. In paragraph (e)(3), revising the second and third sentences;

■ b. Revising paragraph (e)(4);

■ c. In paragraph (e)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and

■ d. Adding paragraph (f).

The revision and addition read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Michigan's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(f) The owner and operator of each source located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Y—Minnesota

■ 14. Amend § 52.1240 by adding paragraph (d) to read as follows:

§ 52.1240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Minnesota's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart Z—Mississippi

■ 15. Amend § 52.1284 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2):

■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and

■ ii. Removing the second and third sentences;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Mississippi's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart AA—Missouri

■ 16. Amend § 52.1326 by revising paragraph (b)(2) and (3) and adding paragraphs (b)(4) and (5) and (c) to read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii), except to the extent the Administrator's approval is partial or conditional.

(3) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(c) The owner and operator of each source located in the State of Missouri and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart DD—Nevada

■ 17. Add § 52.1492 to read as follows:

§ 52.1492 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Nevada's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within

the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart FF—New Jersey

■ 18. Amend § 52.1584 by:
■ a. In paragraph (e)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (f).

The addition reads as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(f) The owner and operator of each source located in the State of New Jersey and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart HH—New York

■ 19. Amend § 52.1684 by:
■ a. In paragraph (b)(3), revising the second and third sentences;
■ b. Revising paragraph (b)(4);
■ c. In paragraph (b)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (c).

The revision and addition read as follows:

§ 52.1684 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(4) Notwithstanding the provisions of paragraph (b)(3) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (b)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(c) The owner and operator of each source located in the State of New York and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart KK—Ohio

■ 20. Amend § 52.1882 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Ohio and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart LL—Oklahoma

■ 21. Amend § 52.1930 by:
■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);
■ b. In newly redesignated paragraph (a)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. Removing the second and third sentences;
■ c. Revising newly redesignated paragraph (a)(3); and
■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1930 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Oklahoma's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations

of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart NN—Pennsylvania

■ 22. Amend § 52.2040 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2040 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Pennsylvania and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart SS—Texas

■ 23. Amend § 52.2283 by:
■ a. In paragraph (d)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. Removing the second and third sentences;
■ b. Revising paragraph (d)(3); and
■ c. Adding paragraphs (d)(4) and (5) and (e).

The revision and additions read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (d)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(e) The owner and operator of each source located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart TT—Utah

■ 24. Add § 52.2356 to read as follows:

§ 52.2356 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal

Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Utah's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart VV—Virginia

■ 25. Amend § 52.2440 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart XX—West Virginia

■ 26. Amend § 52.2540 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of West Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, § 52.45, or § 52.46 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart YY—Wisconsin

■ 27. Amend § 52.2587 by:
■ a. In paragraph (e)(2):
■ i. Removing ''2017 and each subsequent year'' and adding in its place ''2017 through 2022''; and
■ ii. Removing the second and third sentences;
■ b. Revising paragraph (e)(3); and
■ c. Adding paragraphs (e)(4) and (5).

The revision and additions read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Wisconsin's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (e)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

PART 75—CONTINUOUS EMISSION MONITORING

■ 28. The authority citation for part 75 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q and 7651k note.

Subpart H—NO_X Mass Emissions Provisions

■ 29. Amend § 75.72 by:
■ a. In paragraph (c)(3), removing ''appendix B of this part'' and adding in its place ''appendix B to this part'';
■ b. In paragraph (e)(1)(ii), removing ''heat input from'' and adding in its place ''heat input rate to'';
■ c. In paragraph (e)(2), removing ''appendix D of this part'' and adding in its place ''appendix D to this part''; and

■ d. Adding paragraph (f).

The addition reads as follows:

§ 75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

* * * * *

(f) *Procedures for apportioning hourly NO_X mass emission rate to the unit level.* If the owner or operator of a unit determining hourly NO_X mass emission rate at a common stack under this section is subject to a State or Federal NO_X mass emissions reduction program under subpart GGGGG of part 97 of this chapter or under a state implementation plan approved pursuant to § 52.38(b)(12) of this chapter, then on and after January 1, 2024, the owner or operator shall apportion the hourly NO_X mass emissions rate at the common stack to each unit using the common stack based on the ratio of the hourly heat input rate for each such unit to the total hourly heat input rate for all such units, in conjunction with the appropriate unit and stack operating times, according to the procedures in section 8.5.3 of appendix F to this part.

* * * * *

■ 30. Amend § 75.73 by:

■ a. Revising paragraph (a)(3);

■ b. In paragraph (c)(1), removing ''NOX emissions'' and adding in its place ''NO_X emissions'';

■ c. Adding a heading to paragraph (c)(2);

■ d. Revising paragraphs (c)(3) and (f)(1) introductory text;

■ e. Removing and reserving paragraph (f)(1)(i)(B);

■ f. In paragraph (f)(1)(ii)(G), removing ''appendix D;'' and adding in its place ''appendix D to this part;'';

■ g. Adding paragraphs (f)(1)(ix) and (x);

■ h. Adding a heading to paragraph (f)(2); and

■ i. Revising paragraph (f)(4).

The revisions and additions read as follows:

§ 75.73 Recordkeeping and reporting.

(a) * * *

(3) For each hour when the unit is operating, NO_X mass emission rate, calculated in accordance with section 8 of appendix F to this part.

* * * * *

(c) * * *

(2) *Monitoring plan updates.* * * *

(3) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53(h)(1)(i) and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. For units using the low mass emissions excepted methodology under § 75.19, the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (ii). The monitoring plan also shall include a seasonal controls indicator and an ozone season fuel-switching flag.

* * * * *

(f) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the information provided in paragraphs (f)(1)(i) through (x) of this section and shall also include the date of report generation. A unit placed into long-term cold storage is exempted from submitting quarterly reports beginning with the calendar quarter following the quarter in which the unit is placed into long-term cold storage, provided that the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit).

* * * * *

(ix) On and after on January 1, 2024, for a unit subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter and determining NO_X mass emission rate at a common stack, apportioned hourly NO_X mass emission rate for the unit, lb/hr.

(x) On and after January 1, 2024, for a unit that is subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter, that lists coal or a solid coal-derived fuel as a fuel in the unit's monitoring plan under § 75.53 for any portion of the ozone season in the year for which data are being reported, that serves a generator of 100 MW or larger nameplate capacity, and that is not a circulating fluidized bed boiler, provided that through December 31, 2029, the requirements under this paragraph (f)(1)(x) shall apply to a unit in a given calendar year only if the unit also was equipped with selective catalytic reduction controls on or before September 30 of the previous year:

(A) Daily NO_X emissions (lbs) for each day of the reporting period;

(B) Daily heat input (mmBtu) for each day of the reporting period;

(C) Daily average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) for each day of the reporting period;

(D) Daily NO_X emissions (lbs) exceeding the applicable backstop daily NO_X emission rate for each day of the reporting period;

(E) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season; and

(F) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season by more than 50 tons, calculated as the remainder of the amount calculated under paragraph (f)(1)(x)(E) of this section minus 50, but not less than zero.

(2) *Verification of identification codes and formulas.* * * *

(4) *Electronic format, method of submission, and explanatory information.* The designated representative shall comply with all of the quarterly reporting requirements in § 75.64(d), (f), and (g).

■ 31. Revise § 75.75 to read as follows:

§ 75.75 Additional ozone season calculation procedures.

(a) The owner or operator of a unit that is required to calculate daily or ozone season heat input shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the day or ozone season.

(b) The owner or operator of a unit that is required to determine daily or ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing daily or ozone season NO_X mass emissions (in lbs) determined in accordance with this subpart, by daily or ozone season heat input determined in accordance with paragraph (a) of this section.

■ 32. Amend appendix F to part 75 by:

■ a. Adding section 5.3.3;

■ b. In section 8.1.2, revising the introductory text preceding Equation F–25;

■ c. In section 8.4, revising the introductory text, paragraph (a) introductory text (preceding Equation F–27), and paragraph (b) introductory text (preceding Equation F–27a) and adding paragraph (c);

■ d. In section 8.5.2, removing ''the hourly NO_X mass emissions at each unit'' and adding in its place ''hourly NO_X mass emissions at the common stack''; and

■ e. Adding section 8.5.3.

The additions and revisions read as follows:

Appendix F to Part 75—Conversion Procedures

* * * * *

5. Procedures for Heat Input

* * * * *

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

* * * * *

5.3.3 Calculate total daily heat input for a unit using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_d = \sum_{h=1}^{24} HI_h t_h$$

(Eq. F-18c)

Where:

HI_d = Total heat input for a unit for the day, mmBtu.

HI_h = Heat input rate for the unit for hour ''h'' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b to this appendix, mmBtu/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8. Procedures for NO_X Mass Emissions

* * * * *

8.1.2 If NO_X emission rate is measured at a common stack and heat input rate is measured at the unit level, calculate the hourly heat input rate at the common stack according to the following formula:

* * * * *

8.4 Use the following equations to calculate daily, quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F–27 to this appendix to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons.

* * * * *

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F–27a to this appendix to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons.

* * * * *

(c) To calculate daily NO_X mass emissions for a unit in pounds, use Eq. F–27b to this appendix.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h}\, t_h$$

(Eq. F-27b)

Where:

$M_{(NOX)d}$ = NO_X mass emissions for a unit for the day, pounds.

$E_{(NOX)h}$ = NO_X mass emission rate for the unit for hour ''h'' from Equation F–24a, F–26a, F–26b, or F–28, lb/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8.5.3 Where applicable, the owner or operator of a unit that determines hourly NO_X mass emission rate at a common stack shall apportion hourly NO_X mass emissions rate to the units using the common stack based on the hourly heat input rate, using Equation F–28 to this appendix:

$$E_{(NOX)_i} = E_{(NOX)_{CS}} \left(\frac{t_{CS}}{t_i}\right) \left[\frac{HI_i t_i}{\sum_{i=1}^{n} HI_i t_i}\right]$$

(Eq. F-28)

Where:

$E_{(NOX)i}$ = Apportioned NO_X mass emission rate for the hour for unit ''i'', lb/hr.

$E_{(NOX)CS}$ = NO_X mass emission rate for the hour at the common stack, lb/hr.

HI_i = Heat input rate for the hour for unit ''i'','' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b to this appendix, mmBtu/hr.

t_i = Operating time for unit ''i'', fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS} = Common stack operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Number of units using the common stack.

i = Designation of a particular unit.

* * * * *

PART 78—APPEAL PROCEDURES

■ 33. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 34. Amend § 78.1 by:

■ a. In paragraphs (b)(13)(i), (b)(14)(i), (b)(15)(i), (b)(16)(i), and (b)(17)(i), removing ''decision on the'' and adding in its place ''calculation of an'';

■ b. In paragraph (b)(17)(viii), adding ''or (e)'' after ''§ 97.826(d)'';
■ c. In paragraph (b)(17)(ix), adding ''or (e)'' after ''§ 97.811(d)'';
■ d. In paragraph (b)(18)(i), removing ''decision on the'' and adding in its place ''calculation of an''; and
■ e. Revising paragraph (b)(19).

The revision reads as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(19) Under subpart GGGGG of part 97 of this chapter:

(i) The calculation of a dynamic trading budget under § 97.1010(a)(4) of this chapter.

(ii) The calculation of an allocation of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1011 or § 97.1012 of this chapter.

(iii) The decision on the transfer of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1023 of this chapter.

(iv) The decision on the deduction of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1024, § 97.1025, or § 97.1026(d) of this chapter.

(v) The correction of an error in an Allowance Management System account under § 97.1027 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CSAPR NO_X Ozone Season Group 3 allowances based on the information as adjusted under § 97.1028 of this chapter.

(vii) The finalization of control period emissions data, including retroactive adjustment based on audit.

(viii) The approval or disapproval of a petition under § 97.1035 of this chapter.

* * * * *

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, CSAPR NO_X AND SO_2 TRADING PROGRAMS, AND TEXAS SO_2 TRADING PROGRAM

■ 35. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7491, 7601, and 7651, *et seq.*

Subpart AAAAA—CSAPR NO_X Annual Trading Program

§ 97.402 [Amended]

■ 36. Amend § 97.402 by:
■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';
■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''; and

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

§ 97.411 [Amended]

■ 37. Amend § 97.411 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.412 [Amended]

■ 38. Amend § 97.412 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.426 [Amended]

■ 39. In § 97.426, amend paragraph (c) by:

■ a. Removing ''set forth in'' and adding in its place ''established under''; and

■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart BBBBB—CSAPR NO_X Ozone Season Group 1 Trading Program

§ 97.502 [Amended]

■ 40. Amend § 97.502 by:
■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';
■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'':
■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and
■ ii. Adding ''or less'' after ''one ton'';
■ d. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and
■ e. In the definition of ''State'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and''.

§ 97.511 [Amended]

■ 41. Amend § 97.511 by:
■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and
■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.512 [Amended]

■ 42. Amend § 97.512 by:
■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';
■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';
■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';
■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the

State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

■ 43. Amend § 97.526 by:

■ a. In paragraph (c):

■ i. Removing ''set forth in'' and adding in its place ''established under''; and

■ ii. Removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ b. In paragraph (d)(1) introductory text, removing ''§ 52.38(b)(2)(i) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(i)(A) of this chapter (and'';

■ c. In paragraph (d)(1)(ii), removing ''except a State listed in § 52.38(b)(2)(i)'' and adding in its place ''listed in § 52.38(b)(2)(ii)'';

■ d. In paragraph (d)(1)(iv), removing ''§ 52.38(b)(2)(iii) or (iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii) of this chapter (and'';

■ e. Revising paragraph (d)(2)(i);

■ f. In paragraph (d)(2)(ii), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and'';

■ g. Adding paragraph (d)(2)(iii);

■ h. In paragraph (e)(1), removing ''§ 52.38(b)(2)(ii) of this chapter (or Indian'' and adding in its place ''§ 52.38(b)(2)(i)(B) of this chapter (and Indian'';

■ i. In paragraph (e)(2), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii)(B) of this chapter (and''; and

■ j. Adding paragraph (e)(3).

The revisions and additions read as follows:

§ 97.526 Banking and conversion.

* * * * *

(d) * * *

(2)(i) Except as provided in paragraphs (d)(2)(ii) and (iii) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(ii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for the control period in 2017 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section.

* * * * *

(iii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

(e) * * *

(3) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), the owner or operator of a CSAPR NO_X Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program

§ 97.602 [Amended]

■ 44. Amend § 97.602 by:

■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''; and

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

§ 97.611 [Amended]

■ 45. Amend § 97.611 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.612 [Amended]

■ 46. Amend § 97.612 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.626 [Amended]

■ 47. In § 97.626, amend paragraph (c) by:

■ a. Removing ''set forth in'' and adding in its place ''established under''; and

■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart DDDDD—CSAPR SO_2 Group 2 Trading Program

■ 48. Amend § 97.702 by:
■ a. In the definition of ''Alternate designated representative'', removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';
■ b. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';
■ c. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ d. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and
■ e. In the definition of ''Designated representative'', removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

The addition reads as follows:

§ 97.702 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.711 [Amended]

■ 49. Amend § 97.711 by:
■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and
■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.712 [Amended]

■ 50. Amend § 97.712 by:
■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';
■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';
■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';
■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and
■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.726 [Amended]

■ 51. In § 97.726, amend paragraph (c) by:
■ a. Removing ''set forth in'' and adding in its place ''established under''; and
■ b. Removing ''State (or Indian'' and adding in its place ''State (and Indian''.

§ 97.734 [Amended]

■ 52. In § 97.734, amend paragraph (d)(3) by removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

■ 53. Amend § 97.802 by:
■ a. In the definition of ''Assurance account'', removing ''base CSAPR'' and adding in its place ''CSAPR'';
■ b. Removing the definitions for ''Base CSAPR NO_X Ozone Season Group 2 source'' and ''Base CSAPR NO_X Ozone Season Group 2 unit'';
■ c. In the definition of ''Common designated representative'', removing ''base CSAPR'' and adding in its place ''CSAPR'';
■ d. In the definition of ''Common designated representative's assurance level'', revising paragraph (1);
■ e. In the definition of ''Common designated representative's share'', removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;
■ f. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ g. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'':
■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and
■ ii. Adding ''or less'' after ''one ton'';
■ h. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and
■ i. In the definition of ''State'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''.

The revision reads as follows:

§ 97.802 Definitions.

* * * * *

Common designated representative's assurance level * * *

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 2 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 2 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_X Ozone Season Group 2 units in accordance with the CSAPR NO_X Ozone Season Group 2 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(8) or (9) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 2 trading budget under § 97.810(a) and the State's variability limit under § 97.810(b) for such control period, and divided by such State NO_X Ozone Season Group 2 trading budget;

* * * * *

§ 97.806 [Amended]

■ 54. Amend § 97.806 by:
■ a. In paragraphs (c)(2)(i) introductory text, (c)(2)(i)(B), and (c)(2)(iii) and (iv),

removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ b. In paragraph (c)(3)(i), removing ''paragraph (c)(1)'' and adding in its place ''paragraphs (c)(1) and (2)''; and

■ c. Removing and reserving paragraph (c)(3)(ii).

§ 97.810 [Amended]

■ 55. In § 97.810, amend paragraphs (a)(1)(i) through (iii), (a)(2)(i) and (ii), (a)(12)(i) through (iii), (a)(13)(i) and (ii), (a)(17)(i) through (iii), (a)(20)(i) through (iii), (a)(23)(i) through (iii), and (b)(1), (2), (12), (13), (17), (20), and (23) by removing ''and thereafter'' and adding in its place ''through 2022''.

■ 56. Amend § 97.811 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance'';

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance'';

■ c. In paragraph (d)(1), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii)(B) of this chapter (and''; and

■ d. Adding paragraph (e).

The addition reads as follows:

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

* * * * *

(e) *Recall of CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods after 2022.* (1) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b) of this chapter, the provisions of this paragraph (e)(1) and paragraphs (e)(2) through (7) of this section shall apply with regard to each CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period after 2022 to any unit (including a permanently retired unit qualifying for an exemption under § 97.805) in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) and that was initially recorded in the compliance account for the source that includes the unit, whether such CSAPR NO_X Ozone Season Group 2 allowance was allocated pursuant to this subpart or pursuant to a SIP revision approved under § 52.38(b) of this chapter and whether such CSAPR NO_X Ozone Season Group 2 allowance remains in such compliance account or has been transferred to another Allowance Management System account.

(2)(i) For each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section that was allocated for a given control period and initially recorded in a given source's compliance account, one CSAPR NO_X Ozone Season Group 2 allowance that was allocated for the same or an earlier control period and initially recorded in the same or any other Allowance Management System account must be surrendered in accordance with the procedures in paragraphs (e)(3) and (4) of this section.

(ii)(A) The surrender requirement under paragraph (e)(2)(i) of this section corresponding to each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section initially recorded in a given source's compliance account shall apply to such source's current owners and operators, except as provided in paragraph (e)(2)(ii)(B) of this section.

(B) If the owners and operators of a given source as of a given date assumed ownership and operational control of the source through a transaction that did not also provide rights to direct the use or transfer of a given CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section with regard to such source (whether recordation of such CSAPR NO_X Ozone Season Group 2 allowance in the source's compliance account occurred before such transaction or was anticipated to occur after such transaction), then the surrender requirement under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowance shall apply to the most recent former owners and operators of the source before the occurrence of such a transaction.

(C) The Administrator will not adjudicate any private legal dispute among the owners and operators of a source or among the former owners and operators of a source, including any disputes relating to the requirements to surrender CSAPR NO_X Ozone Season Group 2 allowances for the source under paragraph (e)(2)(i) of this section.

(3)(i) As soon as practicable on or after August 4, 2023, the Administrator will send a notification to the designated representative for each source described in paragraph (e)(1) of this section identifying the amounts of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account and the corresponding surrender requirements for the source under paragraph (e)(2)(i) of this section.

(ii) As soon as practicable on or after August 21, 2023, the Administrator will deduct from the compliance account for each source described in paragraph (e)(1) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such compliance account.

(iii) As soon as practicable after completion of the deductions under paragraph (e)(3)(ii) of this section, the Administrator will identify for each source described in paragraph (e)(1) of this section the amounts, if any, of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account for which the corresponding surrender requirements under paragraph (e)(2)(i) of this section have not been satisfied and will send a notification concerning such identified amounts to the designated representative for the source.

(iv) With regard to each source for which unsatisfied surrender requirements under paragraph (e)(2)(i) of this section remain after the deductions under paragraph (e)(3)(ii) of this section:

(A) Except as provided in paragraph (e)(3)(iv)(B) of this section, not later than September 15, 2023, the owners and operators of the source shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such unsatisfied surrender requirements under paragraph (e)(2)(i) of this section in the source's compliance account.

(B) With regard to any portion of such unsatisfied surrender requirements that apply to former owners and operators of the source pursuant to paragraph (e)(2)(ii)(B) of this section, not later than September 15, 2023, such former owners and operators shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such portion of the unsatisfied surrender requirements under paragraph (e)(2)(i) of this section either in the source's compliance account or in another Allowance Management System account identified to the Administrator on or before such date in a submission by the authorized account representative for such account.

(C) As soon as practicable on or after September 15, 2023, the Administrator will deduct from the Allowance

Management System account identified in accordance with paragraph (e)(3)(iv)(A) or (B) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such account.

(v) When making deductions under paragraph (e)(3)(ii) or (iv) of this section to address the surrender requirements under paragraph (e)(2)(i) of this section for a given source:

(A) The Administrator will make deductions to address any surrender requirements with regard to first the 2023 control period and then the 2024 control period.

(B) When making deductions to address the surrender requirements with regard to a given control period, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for such given control period and will then deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for each successively earlier control period in sequence.

(C) When deducting CSAPR NO_X Ozone Season Group 2 allowances allocated for a given control period from a given Allowance Management System account, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances initially recorded in the account under § 97.821 (if the account is a compliance account) in the order of recordation and will then deduct CSAPR NO_X Ozone Season Group 2 allowances recorded in the account under § 97.526(d) or § 97.823 in the order of recordation.

(4)(i) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraph (e)(3) of this section, as soon as practicable on or after November 15, 2023, the Administrator will deduct such initially recorded CSAPR NO_X Ozone Season Group 2 allowances from any Allowance Management System accounts in which such CSAPR NO_X Ozone Season Group 2 allowances are held, making such deductions in any order determined by the Administrator, until all such surrender requirements for such source have been satisfied or until all such CSAPR NO_X Ozone Season Group 2 allowances have been deducted, except as provided in paragraph (e)(4)(ii) of this section.

(ii) If no person with an ownership interest in a given CSAPR NO_X Ozone Season Group 2 allowance as of April 30, 2022, was an owner or operator of the source in whose compliance account such CSAPR NO_X Ozone Season Group 2 allowance was initially recorded, was a direct or indirect parent or subsidiary of an owner or operator of such source, or was directly or indirectly under common ownership with an owner or operator of such source, the Administrator will not deduct such CSAPR NO_X Ozone Season Group 2 allowance under paragraph (e)(4)(i) of this section. For purposes of this paragraph (e)(4)(ii), each owner or operator of a source shall be deemed to be a person with an ownership interest in any CSAPR NO_X Ozone Season Group 2 allowance held in that source's compliance account. The limitation established by this paragraph (e)(4)(ii) on the deductibility of certain CSAPR NO_X Ozone Season Group 2 allowances under paragraph (e)(4)(i) of this section shall not be construed as a waiver of the surrender requirements under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowances.

(iii) Not less than 45 days before the planned date for any deductions under paragraph (e)(4)(i) of this section, the Administrator will send a notification to the authorized account representative for the Allowance Management System account from which such deductions will be made identifying the CSAPR NO_X Ozone Season Group 2 allowances to be deducted and the data upon which the Administrator has relied and specifying a process for submission of any objections to such data. Any objections must be submitted to the Administrator not later than 15 days before the planned date for such deductions as indicated in such notification.

(5) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraphs (e)(3) and (4) of this section:

(i) The persons identified in accordance with paragraph (e)(2)(ii) of this section with regard to such source and each such CSAPR NO_X Ozone Season Group 2 allowance shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(ii) Each such CSAPR NO_X Ozone Season Group 2 allowance, and each day in such control period, shall constitute a separate violation of this subpart and the Clean Air Act.

(6) The Administrator will record in the appropriate Allowance Management System accounts all deductions of CSAPR NO_X Ozone Season Group 2 allowances under paragraphs (e)(3) and (4) of this section.

(7)(i) Each submission, objection, or other written communication from a designated representative, authorized account representative, or other person to the Administrator under paragraph (e)(2), (3), or (4) of this section shall be sent electronically to the email address *CSAPR@epa.gov*. Each such communication from a designated representative must contain the certification statement set forth in § 97.814(a), and each such communication from the authorized account representative for a general account must contain the certification statement set forth in § 97.820(c)(2)(ii).

(ii) Each notification from the Administrator to a designated representative or authorized account representative under paragraph (e)(3) or (4) of this section will be sent electronically to the email address most recently received by the Administrator for such representative. In any such notification, the Administrator may provide information by means of a reference to a publicly accessible website where the information is available.

§ 97.812 [Amended]

■ 57. Amend § 97.812 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the

State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.825 [Amended]

■ 58. In § 97.825, amend paragraphs (a) introductory text, (a)(2), (b)(1)(i), (b)(1)(ii)(A) and (B), (b)(3), (b)(4)(i), (b)(5), (b)(6)(i), (b)(6)(iii) introductory text, and (b)(6)(iii)(A) and (B) by removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears.

■ 59. Amend § 97.826 by:

■ a. In paragraph (b), removing ''(c) or (d)'' and adding in its place ''(c), (d), or (e)'';

■ b. In paragraph (c):

■ i. Removing ''set forth in'' and adding in its place ''established under''; and

■ ii. Removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ c. In paragraphs (d)(1)(i)(A) and (B), removing ''§ 52.38(b)(2)(iv)'' and adding in its place ''§ 52.38(b)(2)(ii)(B)'';

■ d. Revising paragraph (d)(1)(i)(C);

■ e. In paragraph (d)(1)(ii) introductory text, removing ''§ 52.38(b)(2)(v)'' and adding in its place ''§ 52.38(b)(2)(iii)(A)'';

■ f. In paragraphs (d)(2)(i) and (d)(3), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and'';

■ g. Redesignating paragraph (e) as paragraph (f) and adding a new paragraph (e); and

■ h. Revising newly redesignated paragraphs (f)(1) and (2).

The revisions and additions read as follows:

§ 97.826 Banking and conversion.

* * * * *

(d) * * *

(1) * * *

(i) * * *

(C) The full-season CSAPR NO_X Ozone Season Group 3 allowance bank target, computed as the sum for all States listed in § 52.38(b)(2)(iii)(A) of this chapter of the variability limits under § 97.1010(e) for such States for the control period in 2022.

* * * * *

(e) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b)(8) or (9) of this chapter:

(1) By September 18, 2023, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted under § 97.822 and, before resuming acceptance of such transfers, will take the following actions with regard to every general account and every compliance account except a compliance account for a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(A) of this chapter (and Indian country within the borders of such a State):

(i) The Administrator will deduct all CSAPR NO_X Ozone Season Group 2 allowances allocated for the control periods in 2017 through 2022 from each such account.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of—

(A) The sum of all CSAPR NO_X Ozone Season Group 2 allowances deducted from all such accounts under paragraph (e)(1)(i) of this section; divided by

(B) The product of the sum of the variability limits for the control period in 2024 under § 97.1010(e) for all States listed in § 52.38(b)(2)(iii)(B) and (C) of this chapter multiplied by a fraction whose numerator is the number of days from August 4, 2023 through September 30, 2023, inclusive, and whose denominator is 153.

(iii) The Administrator will allocate and record in each such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of the number of CSAPR NO_X Ozone Season Group 2 allowances deducted from such account under paragraph (e)(1)(i) of this section divided by the conversion factor determined under paragraph (e)(1)(ii) of this section, except as provided in paragraph (e)(1)(iv) or (v) of this section.

(iv) Where, pursuant to paragraph (e)(1)(i) of this section, the Administrator deducts CSAPR NO_X Ozone Season Group 2 allowances from the compliance account for a source in a State not listed in § 52.38(b)(2)(iii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record CSAPR NO_X Ozone Season Group 3 allowances in that compliance account but instead will allocate and record the amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed for such source in accordance with paragraph (e)(1)(iii) of this section in a general account identified by the designated representative for such source, provided that if the designated representative fails to identify such a general account in a submission to the Administrator by September 18, 2023, the Administrator may record such CSAPR NO_X Ozone Season Group 3 allowances in a general account identified or established by the Administrator with the designated representative as the authorized account representative and with the owners and operators of such source (as indicated on the certificate of representation for the source) as the persons represented by the authorized account representative.

(v)(A) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be allocated to and recorded in general accounts under paragraph (e)(1)(iii) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(B) Following a computation for a group of general accounts in accordance with paragraph (e)(1)(v)(A) of this section, the Administrator will allocate to and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 2 allowances removed from such individual accounts under paragraph (e)(1)(i) of this section.

(C) In determining the proportional shares under paragraph (e)(1)(v)(B) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (e)(1)(v)(A) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances allocated to some individual accounts to equal zero.

(2) After the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 2 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 2 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in

2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

(f) * * *

(1) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2017 through 2020 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (d)(1)(i)(D) of this section.

(2) After the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2017 through 2022 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

Subpart FFFFF—Texas SO_2 Trading Program

■ 60. Amend § 97.902 by:

■ a. In the definition of ''Alternate designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and

■ d. In the definition of ''Designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

The addition reads as follows:

§ 97.902 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.934 [Amended]

■ 61. In § 97.934, amend paragraph (d)(3) by removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart GGGGG—CSAPR NO_X Ozone Season Group 3 Trading Program

■ 62. Amend § 97.1002 by:

■ a. Revising the definition of ''Allocate or allocation'';

■ b. In the definition of ''Allowance transfer deadline'', adding ''primary'' before ''emissions limitation'';

■ c. In the definition of ''Alternate designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then'';

■ d. In the definition of ''Assurance account'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ e. Adding in alphabetical order a definition for ''Backstop daily NO_X emissions rate'';

■ f. Removing the definitions for ''Base CSAPR NO_X Ozone Season Group 3 source'' and ''Base CSAPR NO_X Ozone Season Group 3 unit'';

■ g. Adding in alphabetical order a definition for ''Coal-derived fuel'';

■ h. In the definition of ''Common designated representative'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ i. Revising the definition of ''Common designated representative's assurance level'';

■ j. In the definition of ''Common designated representative's share'', removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ k. In the definition of ''Compliance account'', adding ''primary'' before ''emissions limitation'';

■ l. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 1 Trading Program'';

■ m. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ n. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'':

■ i. Adding ''or (e)'' after ''§ 97.826(d)''; and

■ ii. Adding ''or less'' after ''one ton'';

■ o. In the definitions of ''CSAPR NO_X Ozone Season Group 3 allowance deduction'' and ''CSAPR NO_X Ozone Season Group 3 emissions limitation'', adding ''primary'' before ''emissions limitation'';

■ p. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'';

■ q. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and'';

■ r. Adding in alphabetical order a definition for ''CSAPR SO_2 Group 2 Trading Program'';

■ s. In the definition of ''Designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then''.

■ t. In the definition of ''Excess emissions'', adding ''primary'' before ''emissions limitation'';

■ u. Adding in alphabetical order a definition for ''Historical control period''; and

■ v. In the definition of ''State'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

The revisions and additions read as follows:

§ 97.1002 Definitions.

* * * * *

Allocate or *allocation* means, with regard to CSAPR NO_X Ozone Season Group 3 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart, §§ 97.526(d) and 97.826(d) and (e), and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(10), (11), or (12) of this chapter, of the amount of such CSAPR NO_X Ozone Season Group 3 allowances to be initially credited, at no cost to the recipient, to:

(1) A CSAPR NO_X Ozone Season Group 3 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside;

(4) An Indian country existing unit set-aside; or

(5) An entity not listed in paragraphs (1) through (4) of this definition;

(6) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_X Ozone Season Group 3 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_X Ozone Season Group 3 allowances, the CSAPR NO_X Ozone Season Group 3 unit will be treated as being allocated an amount (*i.e.,* zero) of CSAPR NO_X Ozone Season Group 3 allowances.

* * * * *

Backstop daily NO_X emissions rate means a NO_X emissions rate used in the determination of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation for a CSAPR NO_X Ozone Season Group 3 source in accordance with § 97.1024(b).

* * * * *

Coal-derived fuel means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal.

* * * * *

Common designated representative's assurance level means, with regard to a specific common designated representative and a State (and Indian country within the borders of such State) and control period in a given year for which the State assurance level is exceeded as described in § 97.1006(c)(2)(iii):

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 3 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 3 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 3 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_X Ozone Season Group 3 units in accordance with the CSAPR NO_X Ozone Season Group 3 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(11) or (12) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 3 trading budget under § 97.1010(a) and the State's variability limit under § 97.1010(e) for such control period, and divided by such State NO_X Ozone Season Group 3 trading budget;

(2) Provided that the allocations of CSAPR NO_X Ozone Season Group 3 allowances for any control period taken into account for purposes of this definition shall exclude any CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period under § 97.526(d) or § 97.826(d) or (e).

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i), and (b)(3) through (5) and (13) through (15) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR NO_X Ozone Season Group 3 secondary emissions limitation means, for a CSAPR NO_X Ozone Season Group 3 unit to which such a limitation applies under § 97.1025(c)(1) for a control period in a given year, the tonnage of NO_X emissions calculated for the unit in accordance with § 97.1025(c)(2) for such control period.

* * * * *

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

Historical control period means, for a unit as of a given calendar year, the period starting May 1 of a previous calendar year and ending September 30 of that previous calendar year, inclusive, without regard to whether the unit was subject to requirements under the CSAPR NO_X Ozone Season Group 3 Trading Program during such period.

* * * * *

■ 63. Amend § 97.1006 by:

■ a. Revising paragraph (b)(2), paragraph (c)(1) heading, paragraph (c)(1)(i), and paragraph (c)(1)(ii) introductory text;

■ b. Adding paragraphs (c)(1)(iii) and (iv);

■ c. In paragraphs (c)(2)(i) introductory text and (c)(2)(i)(B), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ d. Revising paragraph (c)(2)(iii);

■ e. In paragraph (c)(2)(iv), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ f. Revising paragraph (c)(3); and

■ g. In paragraph (c)(6) introductory text, adding ''or less'' after ''one ton''.

The revisions and additions read as follows:

§ 97.1006 Standard requirements.

* * * * *

(b) * * *

(2) The emissions and heat input data determined in accordance with §§ 97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 3 allowances under §§ 97.1011 and 97.1012 and to determine compliance with the CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) * * *

(1) *CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations*—(i) *Primary emissions limitation.* As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 3 source and each CSAPR NO_X Ozone

Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 3 allowances available for deduction for such control period under § 97.1024(a) in an amount not less than the amount determined under § 97.1024(b), comprising the sum of—

(A) The tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 3 units at the source; plus

(B) Two times the excess, if any, over 50 tons of the sum, for all CSAPR NO_X Ozone Season Group 3 units at the source and all calendar days of the control period, of any NO_X emissions from such a unit on any calendar day of the control period exceeding the NO_X emissions that would have occurred on that calendar day if the unit had combusted the same daily heat input and emitted at any backstop daily NO_X emissions rate applicable to the unit for that control period.

(ii) *Exceedances of primary emissions limitation.* If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 3 units at a CSAPR NO_X Ozone Season Group 3 source are in excess of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

* * * * *

(iii) *Secondary emissions limitation.* The owner or operator of a CSAPR NO_X Ozone Season Group 3 unit subject to an emissions limitation under § 97.1025(c)(1) shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with § 97.1025(c)(2).

(iv) *Exceedances of secondary emissions limitation.* If total NO_X emissions during a control period in a given year from a CSAPR NO_X Ozone Season Group 3 unit are in excess of the amount of a CSAPR NO_X Ozone Season Group 3 secondary emissions limitation applicable to the unit for the control period under paragraph (c)(1)(iii) of this section, then the owners and operators of the unit and the source at which the unit is located shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) * * *

(iii) Total NO_X emissions from all CSAPR NO_X Ozone Season Group 3 units at CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 3 trading budget under § 97.1010(a) and the State's variability limit under § 97.1010(e).

* * * * *

(3) *Compliance periods.* (i) A CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(i) and (ii) and (c)(2) of this section for the control period starting on the later of the applicable date in paragraph (c)(3)(i)(A), (B), or (C) of this section or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter:

(A) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) August 4, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter.

(ii) A CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(iii) and (iv) of this section for the control period starting on the later of May 1, 2024, or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter.

* * * * *

■ 64. Revise § 97.1010 to read as follows:

§ 97.1010 State NO_X Ozone Season Group 3 trading budgets, set-asides, and variability limits.

(a) *State NO_X Ozone Season Group 3 trading budgets.* (1)(i) The State NO_X Ozone Season Group 3 trading budgets for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 through 2025 shall be as indicated in table 1 to this paragraph (a)(1)(i), subject to prorating for the control period in 2023 as provided in paragraph (a)(1)(ii) of this section:

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD, 2021–2025

[Tons]

State	2021	2022	Portion of 2023 control period before August 4, 2023, before prorating	Portion of 2023 control period on and after August 4, 2023, before prorating	2024	2025
Alabama			13,211	6,379	6,489	6,489
Arkansas			9,210	8,927	8,927	8,927
Illinois	11,223	9,102	8,179	7,474	7,325	7,325
Indiana	17,004	12,582	12,553	12,440	11,413	11,413
Kentucky	17,542	14,051	14,051	13,601	12,999	12,472
Louisiana	16,291	14,818	14,818	9,363	9,363	9,107
Maryland	2,397	1,266	1,266	1,206	1,206	1,206
Michigan	14,384	12,290	9,975	10,727	10,275	10,275
Minnesota				5,504	4,058	4,058
Mississippi			6,315	6,210	5,058	5,037
Missouri			15,780	12,598	11,116	11,116
Nevada				2,368	2,589	2,545
New Jersey	1,565	1,253	1,253	773	773	773
New York	4,079	3,416	3,421	3,912	3,912	3,912
Ohio	13,481	9,773	9,773	9,110	7,929	7,929
Oklahoma			11,641	10,271	9,384	9,376

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD, 2021–2025—Continued

[Tons]

State	2021	2022	Portion of 2023 control period before August 4, 2023, before prorating	Portion of 2023 control period on and after August 4, 2023, before prorating	2024	2025
Pennsylvania	12,071	8,373	8,373	8,138	8,138	8,138
Texas			52,301	40,134	40,134	38,542
Utah				15,755	15,917	15,917
Virginia	6,331	3,897	3,980	3,143	2,756	2,756
West Virginia	15,062	12,884	12,884	13,791	11,958	11,958
Wisconsin			7,915	6,295	6,295	5,988

(ii) For the control period in 2023, the State NO_X Ozone Season Group 3 trading budget for each State shall be calculated as the sum, rounded to the nearest allowance, of the following prorated amounts:

(A) The product of the non-prorated trading budget for the portion of the 2023 control period before August 4, 2023, shown for the State in table 1 to paragraph (a)(1)(i) of this section (or zero if table 1 to paragraph (a)(1)(i) shows no amount for such portion of the 2023 control period for the State) multiplied by a fraction whose numerator is the number of days from May 1, 2023, through the day before August 4, 2023, inclusive, and whose denominator is 153; plus

(B) The product of the non-prorated trading budget for the portion of the 2023 control period on and after August 4, 2023, shown for the State in table 1 to paragraph (a)(1)(i) of this section multiplied by a fraction whose numerator is the number of days from August 4, 2023, through September 30, 2023, inclusive, and whose denominator is 153.

(2)(i) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2026 through 2029 shall be the preset trading budget indicated for the State and control period in table 2 to this paragraph (a)(2)(i), except as provided in paragraph (a)(2)(ii) of this section.

TABLE 2 TO PARAGRAPH (a)(2)(i)—PRESET TRADING BUDGETS BY CONTROL PERIOD, 2026–2029

[Tons]

State	2026	2027	2028	2029
Alabama	6,339	6,236	6,236	5,105
Arkansas	6,365	4,031	4,031	3,582
Illinois	5,889	5,363	4,555	4,050
Indiana	8,363	8,135	7,280	5,808
Kentucky	9,697	7,908	7,837	7,392
Louisiana	6,370	3,792	3,792	3,639
Maryland	842	842	842	842
Michigan	6,743	5,691	5,691	4,656
Minnesota	4,058	2,905	2,905	2,578
Mississippi	3,484	2,084	1,752	1,752
Missouri	9,248	7,329	7,329	7,329
Nevada	1,142	1,113	1,113	880
New Jersey	773	773	773	773
New York	3,650	3,388	3,388	3,388
Ohio	7,929	7,929	6,911	6,409
Oklahoma	6,631	3,917	3,917	3,917
Pennsylvania	7,512	7,158	7,158	4,828
Texas	31,123	23,009	21,623	20,635
Utah	6,258	2,593	2,593	2,593
Virginia	2,565	2,373	2,373	1,951
West Virginia	10,818	9,678	9,678	9,678
Wisconsin	4,990	3,416	3,416	3,416

(ii) If the preset trading budget indicated for a given State and control period in table 2 to paragraph (a)(2)(i) of this section is less than the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section, then the State NO_X Ozone Season Group 3 trading budget for the State and control period shall be the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section.

(3) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2030 and thereafter shall be the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section.

(4) The Administrator will calculate the dynamic trading budget for each State and each control period in 2026

and thereafter in the year before the year of the control period as follows:

(i) The Administrator will include a unit in a State (and Indian country within the borders of the State) in the calculation of the State's dynamic trading budget for a control period if—

(A) To the best of the Administrator's knowledge, the unit qualifies as a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004, without regard to whether the unit has permanently retired, provided that including a unit in the calculation of a dynamic trading budget does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not including a unit in the calculation of a dynamic trading budget does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit;

(B) The unit's deadline for certification of monitoring systems under § 97.1030(b) is on or before May 1 of the year two years before the year of the control period for which the dynamic trading budget is being calculated; and

(C) The owner or operator reported heat input greater than zero for the unit in accordance with part 75 of this chapter for the historical control period in the year two years before the year of the control period for which the dynamic trading budget is being calculated.

(ii) For each unit identified for inclusion in the calculation of the State's dynamic trading budget for a control period under paragraph (a)(4)(i) of this section, the Administrator will calculate the heat input amount in mmBtu to be used in the budget calculation as follows:

(A) For each such unit, the Administrator will determine the following unit-level amounts:

(*1*) The total heat input amounts reported in accordance with part 75 of this chapter for the unit for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the dynamic trading budget is being calculated, except any historical control period that commenced before the unit's first deadline under any regulatory program to begin recording and reporting heat input in accordance with part 75 of this chapter; and

(*2*) The average of the three highest unit-level total heat input amounts identified for the unit under paragraph (a)(4)(iv)(A)(*1*) of this section or, if fewer than three non-zero amounts are identified for the unit, the average of all such non-zero total heat input amounts.

(B) For the State, the Administrator will determine the following state-level amounts:

(*1*) The sum for all units in the State meeting the criterion under paragraph (a)(4)(i)(A) of this section, without regard to whether such units also meet the criteria under paragraphs (a)(4)(i)(B) and (C) of this section, of the total heat input amounts reported in accordance with part 75 of this chapter for the historical control periods in the years two, three, and four years before the year of the control period for which the dynamic trading budget is being calculated, provided that for the historical control periods in 2022 and 2023, the total reported heat input amounts for Nevada and Utah as otherwise determined under this paragraph (a)(4)(ii)(B)(*1*) shall be increased by 13,489,332 mmBtu for Nevada and by 1,888,174 mmBtu for Utah;

(*2*) The average of the three state-level total heat input amounts calculated for the State under paragraph (a)(4)(ii)(B)(*1*) of this section; and

(*3*) The sum for all units identified for inclusion in the calculation of the State's dynamic trading budget for the control period under paragraph (a)(4)(i) of this section of the unit-level average heat input amounts calculated under paragraph (a)(4)(ii)(A)(*2*) of this section.

(C) The heat input amount for a unit used in the calculation of the State's dynamic trading budget shall be the product of the unit-level average total heat input amount calculated for the unit under paragraph (a)(4)(ii)(A)(*2*) of this section multiplied by a fraction whose numerator is the state-level average total heat input amount calculated under paragraph (a)(4)(ii)(B)(*2*) of this section and whose denominator is the state-level sum of the unit-level average heat input amounts calculated under paragraph (a)(4)(ii)(B)(*3*) of this section.

(iii) For each unit identified for inclusion in the calculation of the State's dynamic trading budget for a control period under paragraph (a)(4)(i) of this section, the Administrator will identify the NO_X emissions rate in lb/mmBtu to be used in the calculation as follows:

(A) For a unit listed in the document entitled ''Unit-Specific Ozone Season NO_X Emissions Rates for Dynamic Budget Calculations'' posted at *www.regulations.gov* in docket EPA–HQ–OAR–2021–0668, the NO_X emissions rate used in the calculation for the control period shall be the NO_X emissions rate shown for the unit and control period in that document.

(B) For a unit not listed in the document referenced in paragraph (a)(4)(iii)(A) of this section, the NO_X emissions rate used in the calculation for the control period shall be identified according to the type of unit and the type of fuel combusted by the unit during the control period beginning May 1 on or immediately after the unit's deadline for certification of monitoring systems under § 97.1030(b) as follows:

(*1*) 0.011 lb/mmBtu, for a simple cycle combustion turbine or a combined cycle combustion turbine other than an integrated coal gasification combined cycle unit;

(*2*) 0.030 lb/mmBtu, for a boiler combusting only fuel oil or gaseous fuel (other than coal-derived fuel) during such control period; or

(*3*) 0.050 lb/mmBtu, for a boiler combusting any amount of coal or coal-derived fuel during such control period or any other unit not covered by paragraph (a)(4)(iii)(B)(*1*) or (*2*) of this section.

(iv) The Administrator will calculate the State's dynamic trading budget for the control period as the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all units identified for inclusion in the calculation under paragraph (a)(4)(i) of this section, of the product for each such unit of the heat input amount in mmBtu calculated for the unit under paragraph (a)(4)(ii) of this section multiplied by the NO_X emissions rate in lb/mmBtu identified for the unit under paragraph (a)(4)(iii) of this section.

(v)(A) By March 1, 2025 and March 1 of each year thereafter, the Administrator will calculate the dynamic trading budget for each State, in accordance with paragraphs (a)(4)(i) through (iv) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph (a)(4)(v)(A) and will promulgate a notice of data availability of the results of the calculations.

(B) For each notice of data availability required in paragraph (a)(4)(v)(A) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the units included in the calculations) are in accordance with the provisions referenced in paragraph (a)(4)(v)(A) of this section.

(C) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(4)(v)(A) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(4)(v)(A) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(4)(v)(B) of this section.

(b) *Indian country existing unit set-asides for the control periods in 2023 and thereafter.* The Indian country existing unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2023 and thereafter shall be calculated as the sum of all allowance allocations to units in areas of Indian country within the borders of the State not subject to the State's SIP authority as provided in the applicable notice of data availability for the control period referenced in § 97.1011(a)(2).

(c) *New unit set-asides.* (1) The new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO_X Ozone Season Group 3 trading budgets for such control periods shall be as indicated in table 3 to this paragraph (c)(1):

TABLE 3 TO PARAGRAPH (c)(1)—NEW UNIT SET-ASIDES BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	265	265
Indiana	262	254
Kentucky	309	283
Louisiana	430	430
Maryland	135	115
Michigan	500	482
New Jersey	27	27
New York	168	168
Ohio	291	290
Pennsylvania	335	339
Virginia	185	161
West Virginia	266	261

(2) The new unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2023 and thereafter shall be calculated as the product (rounded to the nearest allowance) of the State NO_X Ozone Season Group 3 trading budget for the State and control period established in accordance with paragraph (a) of this section multiplied by—

(i) 0.09, for Nevada for the control periods in 2023 through 2025;

(ii) 0.06, for Ohio for the control periods in 2023 through 2025;

(iii) 0.05, for each State other than Nevada and Ohio for the control periods in 2023 through 2025; or

(iv) 0.05, for each State for each control period in 2026 and thereafter.

(d) *Indian country new unit set-asides for the control periods in 2021 and 2022.* The Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 for each State with CSAPR NO_X Ozone Season Group 3 trading budgets for such control periods shall be as indicated in table 4 to this paragraph (d):

TABLE 4 TO PARAGRAPH (d)—INDIAN COUNTRY NEW UNIT SET-ASIDES BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	....	....
Indiana	....	....
Kentucky	....	....
Louisiana	15	15
Maryland	....	....
Michigan	13	12
New Jersey	....	....
New York	3	3
Ohio	....	....
Pennsylvania	....	....
Virginia	....	....
West Virginia	....	....

(e) *Variability limits.* (1) The variability limits for the State NO_X Ozone Season Group 3 trading budgets for the control periods in 2021 and 2022 for each State with such trading budgets for such control periods shall be as indicated in table 5 to this paragraph (e)(1).

TABLE 5 TO PARAGRAPH (e)(1)—VARIABILITY LIMITS BY CONTROL PERIOD

[2021–2022 (tons)]

State	2021	2022
Illinois	2,356	1,911
Indiana	3,571	2,642
Kentucky	3,684	2,951
Louisiana	3,421	3,112
Maryland	504	266
Michigan	3,021	2,581
New Jersey	329	263
New York	856	717
Ohio	2,831	2,052
Pennsylvania	2,535	1,758
Virginia	1,329	818
West Virginia	3,163	2,706

(2) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period in 2023 and thereafter shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget for the State and control period established in accordance with paragraph (a) of this section multiplied by the greater of—

(i) 0.21; or

(ii) Any excess over 1.00 of the quotient (rounded to two decimal places) of—

(A) The sum for all CSAPR NO_X Ozone Season Group 3 units in the State and Indian country within the borders of the State of the total heat input reported for the control period in mmBtu, provided that, for purposes of this paragraph (e)(2)(ii)(A), the 2023 control period for all States shall be deemed to be the period from May 1, 2023 through September 30, 2023, inclusive; divided by

(B) The state-level total heat input amount used in the calculation of the State NO_X Ozone Season Group 3 trading budget for the State and control period in mmBtu, as identified in accordance with paragraph (e)(3) of this section.

(3) For purposes of paragraph (e)(2)(ii)(B) of this section, the state-level total heat input amount used in the calculation of a State NO_X Ozone Season Group 3 trading budget for a given control period shall be identified as follows:

(i) For a control period in 2023 through 2025, and for a control period in 2026 through 2029 if the State NO_X Ozone Season Group 3 trading budget for the State and control period under paragraph (a)(2) of this section is the preset trading budget set forth for the State and control period in table 2 to paragraph (a)(2)(i) of this section, the state-level total heat input amounts shall be as indicated in table 6 to this paragraph (e)(3)(i).

TABLE 6 TO PARAGRAPH (e)(3)(i)—STATE-LEVEL TOTAL HEAT INPUT USED IN CALCULATIONS OF PRESET TRADING BUDGETS BY CONTROL PERIOD

[2023–2029 (mmBtu)]

State	2023	2024	2025	2026	2027	2028	2029
Alabama	313,037,541	333,030,691	333,030,691	330,396,046	328,650,653	328,650,653	307,987,882
Arkansas	192,843,561	192,843,561	192,843,561	190,921,052	190,921,052	190,921,052	190,921,052
Illinois	274,005,935	286,568,112	286,568,112	253,219,463	253,219,463	214,086,655	193,900,867
Indiana	356,047,916	330,175,944	330,175,944	302,245,332	302,245,332	277,218,546	236,611,101
Kentucky	301,161,750	301,161,750	295,857,697	295,857,697	295,857,697	293,016,485	274,595,978
Louisiana	280,592,592	280,592,592	278,766,253	278,461,807	277,262,840	277,262,840	277,262,840
Maryland	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007	70,725,007
Michigan	313,846,533	299,124,688	299,124,688	258,225,107	258,225,107	258,225,107	222,314,181
Minnesota	128,893,685	107,821,236	107,821,236	107,821,236	93,890,928	93,890,928	85,707,385
Mississippi	192,978,295	189,415,018	189,279,160	189,279,160	189,279,160	176,004,820	176,004,820
Missouri	284,308,851	249,153,661	249,153,661	249,153,661	248,413,545	248,413,545	248,413,545
Nevada	103,489,785	116,979,117	114,729,782	105,018,415	100,193,805	100,193,805	96,378,269
New Jersey	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231	112,233,231
New York	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661	242,853,661
Ohio	412,292,609	386,560,212	386,560,212	386,560,212	386,560,212	358,992,155	342,075,946
Oklahoma	212,903,386	211,187,283	211,165,691	211,145,820	196,160,642	196,160,642	196,160,642
Pennsylvania	550,993,363	550,993,363	550,993,363	550,993,363	550,993,363	550,993,363	487,590,728
Texas	1,395,116,925	1,395,116,925	1,389,251,813	1,389,251,813	1,356,192,532	1,320,040,162	1,280,014,875
Utah	164,519,648	166,407,822	166,407,822	127,217,396	127,217,396	127,217,396	127,217,396
Virginia	202,953,791	194,015,719	194,015,719	194,015,719	194,015,719	194,015,719	186,848,587
West Virginia	306,845,495	273,151,957	273,151,957	273,151,957	273,151,957	273,151,957	273,151,957
Wisconsin	220,794,282	220,792,155	213,038,308	185,469,476	151,343,287	151,343,287	151,343,287

(ii) For a control period in 2026 through 2029 if the State NO_X Ozone Season Group 3 trading budget for the State and control period under paragraph (a)(2) of this section is the dynamic trading budget for the State and control period referenced in the applicable notice promulgated under paragraph (a)(4)(v)(C) of this section, and for a control period in 2030 and thereafter, the state-level total heat input amount shall be the amount for the State and control period calculated under paragraph (a)(4)(ii)(B)(*2*) of this section.

(f) *Relationship of trading budgets, set-asides, and variability limits.* Each State NO_X Ozone Season Group 3 trading budget in this section includes any tons in an Indian country existing unit set-aside, a new unit set-aside, or an Indian country new unit set-aside but does not include any tons in a variability limit.

■ 65. Amend § 97.1011 by revising the section heading and paragraphs (a), (b), paragraph (c) heading, and paragraphs (c)(1) and (5) to read as follows:

§ 97.1011 CSAPR NO_X Ozone Season Group 3 allowance allocations to existing units.

(a) *Allocations to existing units in general.* (1) For the control periods in 2021 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in each State and areas of Indian country within the borders of the State subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2026, the notices of data availability will be the notices issued under paragraph (b)(11)(iii) of this section.

(2) For the control periods in 2023 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in areas of Indian country within the borders of each State not subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2026, the notices of data availability will be the notices issued under paragraph (b)(11)(iii) of this section.

(3) Providing an allocation to a unit in a notice of data availability does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit.

(b) *Calculation of default allocations to existing units for control periods in 2026 and thereafter.* For each control period in 2026 and thereafter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of Indian country within the borders of the State, the Administrator will calculate default allocations of CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) For each State and control period, the total amount of CSAPR NO_X Ozone Season Group 3 allowances for which the Administrator will calculate default allocations shall be the remainder of the State NO_X Ozone Season Group 3 trading budget for the control period under § 97.1010(a) minus the new unit set-aside for the control period under § 97.1010(c).

(2) The Administrator will calculate a default allocation of CSAPR NO_X Ozone Season Group 3 allowances for each CSAPR NO_X Ozone Season Group 3 unit in the State and Indian country within the borders of the State meeting the following criteria:

(i) To the best of the Administrator's knowledge, the unit qualifies as a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004, without regard to whether the unit has permanently retired;

(ii) The unit's deadline for certification of monitoring systems under § 97.1030(b) is on or before May 1 of the year two years before the year of the control period for which the allowances are being allocated; and

(iii) The owner or operator reported heat input greater than zero for the unit in accordance with part 75 of this chapter for the historical control period in the year two years before the year of the control period for which the allowances are being allocated.

(3) For each CSAPR NO_X Ozone Season Group 3 unit for which a default allocation is being calculated for a control period, the Administrator will calculate an average heat input amount to be used in the allocation calculations as follows:

(i) The Administrator will identify the total heat input amounts reported for the unit in accordance with part 75 of this chapter for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the allowances are being allocated, except any historical control period that commenced before the unit's first deadline under any regulatory program to begin recording and reporting heat input in accordance with part 75 of this chapter.

(ii) The average heat input amount used in the allocation calculations shall be the average of the three highest total heat input amounts identified for the unit under paragraph (b)(3)(i) of this section or, if fewer than three non-zero amounts are identified for the unit, the average of all such non-zero total heat input amounts.

(4) For each CSAPR NO_X Ozone Season Group 3 unit for which a default allocation is being calculated for a control period, the Administrator will calculate a tentative maximum allocation amount to be used in the allocation calculations as follows:

(i) The Administrator will identify the total NO_X emissions amounts reported for the unit in accordance with part 75 of this chapter for the historical control periods in the years two, three, four, five, and six years before the year of the control period for which the allowances are being allocated.

(ii) The tentative maximum allocation amount used in the allocation calculations shall be the highest of the total NO_X emissions amounts identified for the unit under paragraph (b)(4)(i) of this section or, if less, any applicable amount calculated under paragraph (b)(4)(iii) of this section.

(iii)(A) The tentative maximum allocation amount under paragraph (b)(4)(ii) of this section for a unit described in paragraph (b)(4)(iii)(B) or (C) of this section may not exceed a maximum controlled baseline calculated as the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of the highest total heat input amount identified for the unit under paragraph (b)(3)(i) of this section in mmBtu multiplied by a NO_X emissions rate of 0.08 lb/mmBtu.

(B) For the control period in 2026, a maximum controlled baseline under paragraph (b)(4)(iii)(A) of this section shall apply to any unit that combusted any coal or solid coal-derived fuel during the historical control period for which the unit's heat input was most recently reported, that serves a generator with nameplate capacity of 100 MW or more, and that is equipped with selective catalytic reduction controls, except a circulating fluidized bed boiler.

(C) For each control period in 2027 and thereafter, a maximum controlled baseline under paragraph (b)(4)(iii)(A) of this section shall apply to any unit that combusted any coal or solid coal-derived fuel during the historical control period for which the unit's heat input was most recently reported and that serves a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

(5) The Administrator will calculate the initial unrounded default allocations for each CSAPR NO_X Ozone Season Group 3 unit according to the procedure in paragraph (b)(6) of this section and will recalculate the unrounded default allocations according to the procedures in paragraph (b)(7) or (8) of this section, as applicable, iterating the recalculations as necessary until the total of the unrounded default allocations to all eligible units equals the amount of allowances determined for the State under paragraph (b)(1) of this section.

(6) The Administrator will calculate the initial unrounded default allocations to CSAPR NO_X Ozone Season Group 3 units as follows:

(i) The Administrator will calculate the sum, for all units determined under paragraph (b)(2) of this section to be eligible to receive default allocations, of the units' average heat input amounts determined under paragraph (b)(3)(ii) of this section.

(ii) For each unit determined under paragraph (b)(2) of this section to be eligible to receive a default allocation, the Administrator will calculate the unit's unrounded default allocation as the lesser of—

(A) The product of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(i) of this section; and

(B) The unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section.

(iii) If the sum of the unrounded default allocations determined under paragraph (b)(6)(ii) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will follow the procedures in paragraph (b)(7) or (8) of this section, as applicable.

(iv) If the sum of the unrounded default allocations determined under paragraph (b)(6)(ii) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(9) and (10) of this section.

(7) If the unrounded default allocation determined in the previous round of the calculation procedure for at least one CSAPR NO_X Ozone Season Group 3 unit is less than the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round of the calculation procedure for all units determined under paragraph (b)(2) of this section to be eligible to receive default allocations.

(ii) The Administrator will calculate the sum, for all units whose unrounded default allocations determined in the previous round of the calculation procedure were less than the respective units' tentative maximum allocation amounts determined under paragraph (b)(4)(ii) of this section, of the units' average heat input amounts determined under paragraph (b)(3)(ii) of this section.

(iii) For each unit whose unrounded default allocation determined in the previous round of the calculation procedure was less than the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unit's unrounded default allocation as the lesser of—

(A) The sum of the unit's unrounded default allocation determined in the previous round of the calculation procedure plus the product of the additional pool of allowances determined under paragraph (b)(7)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(7)(ii) of this section; and

(B) The unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section.

(iv) Except as provided in paragraph (b)(7)(iii) of this section, a unit's unrounded default allocation shall equal the amount determined in the previous round of the calculation procedure.

(v) If the sum of the unrounded default allocations determined under paragraphs (b)(7)(iii) and (iv) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will iterate the procedures in paragraph (b)(7) of this section or follow the procedures in paragraph (b)(8) of this section, as applicable.

(vi) If the sum of the unrounded default allocations determined under paragraphs (b)(7)(iii) and (iv) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(9) and (10) of this section.

(8) If the unrounded default allocation determined in the previous round of the calculation procedure for every CSAPR NO_X Ozone Season Group 3 unit equals the unit's tentative maximum allocation amount determined under paragraph (b)(4)(ii) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round of the calculation procedure for all units determined under paragraph (b)(2) of this section to be eligible to receive default allocations.

(ii) The Administrator will recalculate the unrounded default allocation for each eligible unit as the sum of—

(A) The unit's unrounded default allocation as determined in the previous round of the calculation procedure; plus

(B) The product of the additional pool of allowances determined under paragraph (b)(8)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input amount determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(i) of this section.

(9) The Administrator will round the default allocation for each eligible unit determined under paragraph (b)(6), (7), or (8) of this section to the nearest allowance and make any adjustments required under paragraph (b)(10) of this section.

(10) If the sum of the default allocations after rounding under paragraph (b)(9) of this section does not equal the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will adjust the default allocations as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 3 units in descending order based on such units' allocation amounts under paragraph (b)(9) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant sources' names and numerical order of the relevant units' identification numbers, and will adjust each unit's allocation amount upward or downward by one CSAPR NO_X Ozone Season Group 3 allowance (but not below zero) in the order in which the units are listed, and will repeat this adjustment process as necessary, until the total of the adjusted default allocations equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section.

(11)(i) By March 1, 2025 and March 1 of each year thereafter, the Administrator will calculate the default allocation of CSAPR NO_X Ozone Season Group 3 allowances to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State, in accordance with paragraphs (b)(1) through (10) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph (b)(11)(i) and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(11)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(11)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(11)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(11)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(11)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to existing units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period to a recipient covered by the provisions of paragraph (c)(1)(i), (ii), or (iii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under paragraph (a)(1) or (2) of this section;

(ii) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 3 units as of the first day of such control period; or

(iii) The recipient is not located as of the first day of the control period in the State (and Indian country within the borders of the State) from whose NO_X Ozone Season Group 3 trading budget CSAPR NO_X Ozone Season Group 3 allowances were allocated to the recipient for such control period under paragraph (a)(1) or (2) of this section or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter.

* * * * *

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for 2021, 2022, or 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, and on or before May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, and after May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 66. Amend § 97.1012 by:
■ a. Revising paragraphs (a) introductory text and (a)(1)(i) and (ii);
■ b. Removing paragraphs (a)(1)(iii) and (iv);
■ c. Revising paragraphs (a)(2) and (a)(3)(i);
■ d. In paragraph (a)(3)(ii), adding ''and'' after the semicolon;
■ e. Revising paragraph (a)(3)(iii);
■ f. Removing paragraph (a)(3)(iv);
■ g. Revising paragraph (a)(4)(i);
■ h. Redesignating paragraph (a)(4)(ii) as paragraph (a)(4)(iii) and adding a new paragraph (a)(4)(ii);
■ i. Revising paragraphs (a)(5) and (10):
■ j. In paragraph (a)(11), removing ''§ 97.1011(b)(1)(i), (ii), and (v), of'' and adding in its place ''paragraph (a)(13) of this section, of'';
■ k. Adding paragraph (a)(13);
■ l. Revising paragraphs (b) introductory text and (b)(1) and (2);
■ m. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ n. Revising paragraph (b)(10);
■ o. In paragraph (b)(11), removing ''§ 97.1011(b)(2)(i), (ii), and (v), of'' and adding in its place ''paragraph (b)(13) of this section, of''; and
■ p. Adding paragraphs (b)(13) and (c).

The revisions and additions read as follows:

§ 97.1012 CSAPR NO_X Ozone Season Group 3 allowance allocations to new units.

(a) *Allocations from new unit set-asides.* For each control period in 2021 and thereafter for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or 2023 and thereafter for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority), the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) * * *

(i) CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period; or

(ii) CSAPR NO_X Ozone Season Group 3 units whose allocation of an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) is covered by § 97.1011(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(c) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with § 97.1011(c)(5) and paragraphs (b)(10) and (c)(5) of this section.

(3) * * *

(i) The control period in 2021, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or the control period in 2023, for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter;

* * * * *

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_X Ozone Season Group 3 unit operates in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_X Ozone Season Group 3 allowances.

(4)(i) The allocation to each CSAPR NO_X Ozone Season Group 3 unit described in paragraphs (a)(1)(i) through (iii) of this section and for each control period described in paragraph (a)(3) of this section will be an amount equal to the unit's total tons of NO_X emissions during the control period or, if less, any applicable amount calculated under paragraph (a)(4)(ii) of this section.

(ii)(A) The allocation under paragraph (a)(4)(i) of this section to a unit described in paragraph (a)(4)(ii)(B) or (C) of this section may not exceed a maximum controlled baseline calculated as the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of the unit's total heat input during the control period in mmBtu multiplied by a NO_X emissions rate of 0.08 lb/mmBtu.

(B) For a control period in 2024 through 2026, a maximum controlled baseline under paragraph (a)(4)(ii)(A) of this section shall apply to any unit combusting any coal or solid coal-derived fuel during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls on or before September 30 of the preceding control period, except a circulating fluidized bed boiler.

(C) For a control period in 2027 and thereafter, a maximum controlled baseline under paragraph (a)(4)(ii)(A) of this section shall apply to any unit combusting any coal or solid coal-derived fuel during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

(5) The Administrator will calculate the sum of the allocation amounts of CSAPR NO_X Ozone Season Group 3 allowances determined for all such CSAPR NO_X Ozone Season Group 3 units under paragraph (a)(4)(i) of this section in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) for such control period.

* * * * *

(10)(i) For a control period in 2021 or 2022, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and areas of Indian country within the borders of the State subject to the State's

SIP authority and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in the applicable notice of data availability referenced in § 97.1011(a)(1) an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(ii) For a control period in 2023 or thereafter, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and Indian country within the borders of the State and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period by the Administrator in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2), or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter, an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) or (2) or a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the amount of tons in such new unit set-aside for the State for such control period, and rounded to the nearest allowance.

* * * * *

(13)(i) By March 1, 2022, and March 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the State not subject to the State's SIP authority), in accordance with paragraphs (a)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph (a)(13)(i) and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(13)(ii) of this section.

(b) *Allocations from Indian country new unit set-asides.* For the control periods in 2021 and 2022, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, and for the CSAPR NO_X Ozone Season Group 3 units in areas of Indian country within the borders of each such State not subject to the State's SIP authority, the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) The CSAPR NO_X Ozone Season Group 3 allowances will be allocated to CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period, except as provided in paragraph (b)(10) of this section.

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(d) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with paragraph (c)(5) of this section.

* * * * *

(10) If, after completion of the procedures under paragraphs (b)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will transfer such unallocated CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the State for such control period.

* * * * *

(13)(i) By March 1, 2022, and March 1, 2023, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance with paragraphs (b)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph (b)(13)(i) and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(13)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to new units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period under paragraphs (a)(2) through (7) and (12) of this section or paragraphs (b)(2) through (7) and (12) of this section to a recipient that is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of such control period, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021.

(3) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_X Ozone Season Group 3 allowances were recorded an amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_X Ozone Season Group 3 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_X Ozone Season Group 3 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_X Ozone Season Group 3 allowances.

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2023, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside, in the case of allowances allocated under paragraph (a) of this section, or the Indian country new unit set-aside, in the case of allowances allocated under paragraph (b) of this section, for the control period in 2021 or 2022 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2023, and on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the control period in 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 67. Amend § 97.1021 by:
■ a. In paragraph (a), removing "§ 97.1011(a)" and adding in its place "§ 97.1011(a)(1)";
■ b. Revising paragraph (b);
■ c. Removing and reserving paragraph (c);
■ d. Adding paragraphs (d) and (e);
■ e. In paragraph (f), removing "§ 97.1011(a), or" and adding in its place "§ 97.1011(a)(1), or";
■ f. Redesignating paragraphs (g) and (h) as paragraphs (i) and (j), respectively, and adding new paragraphs (g) and (h);
■ g. Revising newly redesignated paragraph (i);
■ h. In newly redesignated paragraph (j), removing "and May 1 of each year thereafter, the" and adding in its place ", and May 1, 2023, the"; and
■ i. In paragraph (m), adding "or (e)" after "§ 97.811(d)" each time it appears.

The revisions and addition read as follows:

§ 97.1021 Recordation of CSAPR NO_X Ozone Season Group 3 allowance allocations and auction results.

* * * * *

(b) By July 29, 2021, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2022.

* * * * *

(d) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2023.

(e) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024, unless the State in which the source is located notifies the Administrator in writing by August 4, 2023, of the State's intent to submit to the Administrator a complete SIP revision by September 1, 2023, meeting the requirements of § 52.38(b)(10)(i) through (iv) of this chapter.

(1) If, by September 1, 2023, the State does not submit to the Administrator such complete SIP revision, the Administrator will record by September 15, 2023, in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

(2) If the State submits to the Administrator by September 1, 2023, and the Administrator approves by March 1, 2024, such complete SIP revision, the Administrator will record by March 1, 2024, in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source as provided in such approved, complete SIP revision for the control period in 2024.

(3) If the State submits to the Administrator by September 1, 2023, and the Administrator does not approve by March 1, 2024, such complete SIP revision, the Administrator will record by March 1, 2024, in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances

allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

* * * * *

(g) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control periods in 2023 and 2024.

(h) By July 1, 2024, and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control period in the year after the year of the applicable recordation deadline under this paragraph (h).

(i) By May 1, 2022, and May 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1012(a) for the control period in the year before the year of the applicable recordation deadline under this paragraph (i).

* * * * *

■ 68. Amend § 97.1024 by:
■ a. Revising the section heading;
■ b. In paragraphs (a) introductory text and (b) introductory text, adding ''primary'' before ''emissions limitation'';
■ c. Revising paragraph (b)(1);
■ d. Adding paragraph (b)(3); and
■ e. In paragraph (c)(2)(ii), adding ''or (e)'' after ''§ 97.826(d)''.

The revisions and addition read as follows:

§ 97.1024 Compliance with CSAPR NO_X Ozone Season Group 3 primary emissions limitation; backstop daily NO_X emissions rate.

* * * * *

(b) * * *

(1) Until the amount of CSAPR NO_X Ozone Season Group 3 allowances deducted equals the sum of:

(i) The number of tons of total NO_X emissions from all CSAPR NO_X Ozone Season Group 3 units at the source for such control period; plus

(ii) Two times the excess, if any, over 50 tons of the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all calendar days in the control period and all CSAPR NO_X Ozone Season Group 3 units at the source to which the backstop daily NO_X emissions rate applies for the control period under paragraph (b)(3) of this section, of any amount by which a unit's NO_X emissions for a given calendar day in pounds exceed the product in pounds of the unit's total heat input in mmBtu for that calendar day multiplied by 0.14 lb/mmBtu; or

* * * * *

(3) The backstop daily NO_X emissions rate of 0.14 lb/mmBtu applies as follows:

(i) For each control period in 2024 through 2029, the backstop daily NO_X emissions rate shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal or solid coal-derived fuel during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls on or before September 30 of the preceding control period, except a circulating fluidized bed boiler.

(ii) For each control in 2030 and thereafter, the backstop daily NO_X emissions rate shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal or solid coal-derived fuel during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

■ 69. Amend § 97.1025 by:
■ a. Revising the section heading;
■ b. In paragraphs (a) introductory text, (a)(2), (b)(1)(i), (b)(1)(ii)(A) and (B), (b)(3), (b)(4)(i), (b)(5), (b)(6)(i), (b)(6)(iii) introductory text, and (b)(6)(iii)(A) and (B), removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears; and
■ c. Adding paragraph (c).

The revision and addition read as follows:

§ 97.1025 Compliance with CSAPR NO_X Ozone Season Group 3 assurance provisions; CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.

* * * * *

(c) *CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.* (1) The owner or operator of a CSAPR NO_X Ozone Season Group 3 unit equipped with selective catalytic reduction controls or selective non-catalytic reduction controls shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with paragraph (c)(2) of this section, provided that the emissions limitation established under this paragraph (c)(1) shall apply to a unit for a control period only if:

(i) The unit is included for the control period in a group of CSAPR NO_X Ozone Season Group 3 units at CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) having a common designated representative and the owners and operators of such units and sources are subject to a requirement for such control period to hold one or more CSAPR NO_X Ozone Season Group 3 allowances under § 97.1006(c)(2)(i) and paragraph (b) of this section with respect to such group; and

(ii) The unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours during the control period and all or portions of at least 367 operating hours during at least one historical control period under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program.

(2) The amount of the emissions limitation applicable to a CSAPR NO_X Ozone Season Group 3 unit for a control period under paragraph (c)(1) of this section, in tons of NO_X, shall be calculated as the sum of 50 plus the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of multiplying—

(i) The total heat input in mmBtu reported for the unit for the control period in accordance with §§ 97.1030 through 97.1035; and

(ii) A NO_X emission rate of 0.10 lb/mmBtu or, if higher, the product of 1.25 times the lowest seasonal average NO_X emission rate in lb/mmBtu achieved by the unit in any historical control period for which the unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, where the unit's seasonal average NO_X emission rate for each such historical control period shall be calculated from such reported data as the quotient (converted to lb/mmBtu at a conversion factor of 2,000 lb/ton, and rounded to the nearest 0.0001 lb/mmBtu) of the unit's total NO_X emissions in tons for the historical control period divided by the unit's total heat input in mmBtu for the historical control period.

■ 70. Amend § 97.1026 by:

■ a. Revising the section heading and paragraph (b);
■ b. In paragraph (c):
■ i. Removing ''set forth in'' and adding in its place ''established under''; and
■ ii. Removing ''State (or Indian'' and adding in its place ''State (and Indian''; and
■ c. Adding paragraph (d).

The revision and addition read as follows:

§ 97.1026 Banking; bank recalibration.

* * * * *

(b) Any CSAPR NO_X Ozone Season Group 3 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_X Ozone Season Group 3 allowance is deducted or transferred under § 97.1011(c), § 97.1012(c), § 97.1023, § 97.1024, § 97.1025, § 97.1027, or § 97.1028 or paragraph (c) or (d) of this section.

* * * * *

(d) Before the allowance transfer deadline for each control period in 2024 and thereafter, the Administrator will deduct amounts of CSAPR NO_X Ozone Season Group 3 allowances issued for the control periods in previous years exceeding the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in accordance with paragraphs (d)(1) through (4) of this section.

(1) As soon as practicable on or after August 1, 2024, and August 1 of each year thereafter, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 3 allowance transfers submitted under § 97.1022 and, before resuming acceptance of such transfers, will take the actions in paragraphs (d)(2) through (4) of this section.

(2) The Administrator will determine each of the following values:

(i) The total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in all compliance and general accounts.

(ii) The CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in the year of the deadline under paragraph (d)(1) of this section, calculated as the product, rounded to the nearest allowance, of the sum for all States listed in § 52.38(b)(2)(iii) of this chapter of the State NO_X Ozone Season Group 3 trading budgets under § 97.1010(a) for such States for such control period multiplied by—

(A) 0.210, for a control period in 2024 through 2029; or

(B) 0.105, for a control period in 2030 and thereafter.

(3) If the total amount of CSAPR NO_X Ozone Season Group 3 allowances determined under paragraph (d)(2)(i) of this section exceeds the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(ii) of this section, then for each compliance account or general account holding CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section, the Administrator will:

(i) Determine the total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in the account.

(ii) Determine the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period, calculated as the product, rounded up to the nearest allowance, of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(ii) of this section multiplied by a fraction whose numerator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section and whose denominator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in all compliance and general accounts determined under paragraph (d)(2)(i) of this section.

(iii) Deduct an amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section equal to any positive remainder of the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section minus the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period determined under paragraph (d)(3)(ii) of this section. The allowances will be deducted on a first-in, first-out basis in the order set forth in § 97.1024(c)(2)(i) and (ii).

(iv) Record the deductions under paragraph (d)(3)(iii) of this section in the account.

(4)(i) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be deducted from general accounts under paragraph (d)(3) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(ii) Following a computation for a group of general accounts in accordance with paragraph (d)(4)(i) of this section, the Administrator will deduct from and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 3 allowances determined for such individual accounts under paragraph (d)(3)(i) of this section.

(iii) In determining the proportional shares under paragraph (d)(4)(ii) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (d)(4)(i) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances remaining in some individual accounts following the deductions to equal zero.

■ 71. Amend § 97.1030 by:
■ a. Revising paragraph (b)(1); and
■ b. In paragraph (b)(3), removing ''(b)(2)'' and adding in its place ''(b)(1) or (2)'' each time it appears.

The revision reads as follows:

§ 97.1030 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) * * *

(1)(i) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(ii) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter;

(iii) August 4, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements; or

(iv) January 31, 2024, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is not required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements.

* * * * *

■ 72. Amend § 97.1034 by:
■ a. Revising paragraph (d)(2)(i); and
■ b. In paragraph (d)(4), removing ''or CSAPR SO_2 Group 1 Trading Program, quarterly'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly''.

The revision reads as follows:

§ 97.1034 Recordkeeping and reporting.

* * * * *

(d) * * *

(2) * * *

(i)(A) The calendar quarter covering May 1, 2021, through June 30, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) The calendar quarter covering May 1, 2023, through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) The calendar quarter covering August 4, 2023, through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter;

* * * * *

[FR Doc. 2023–05744 Filed 6–2–23; 8:45 am]

BILLING CODE 6560–50–P

Motion to Stay, *United States Steel Corporation v. EPA, et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit B

Air Plan Disapprovals; Interstate Transport for Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9,336 (Feb. 13, 2023)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–HQ–OAR–2021–0663; EPA–R02–OAR–2021–0673; EPA–R03–OAR–2021–0872; EPA–R03–OAR–2021–0873; EPA–R04–OAR–2021–0841; EPA–R05–OAR–2022–0006; EPA–R06–OAR–2021–0801; EPA–R07–OAR–2021–0851; EPA–R08–OAR–2022–0315; EPA–R09–OAR–2022–0394; EPA–R09–OAR–2022–0138; FRL–10209–01–OAR]

Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; final agency action.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA or the Agency) is finalizing the disapproval of State Implementation Plan (SIP) submissions for 19 states regarding interstate transport and finalizing a partial approval and partial disapproval of elements of the SIP submission for two states for the 2015 8-hour ozone national ambient air quality standards (NAAQS). The ''good neighbor'' or ''interstate transport'' provision requires that each state's SIP contain adequate provisions to prohibit emissions from within the state from significantly contributing to nonattainment or interfering with maintenance of the NAAQS in other states. This requirement is part of the broader set of ''infrastructure'' requirements, which are designed to ensure that the structural components of each state's air quality management program are adequate to meet the state's responsibilities under the CAA. Disapproving a SIP submission establishes a 2-year deadline for the EPA to promulgate Federal Implementation Plans (FIPs) to address the relevant requirements, unless the EPA approves a subsequent SIP submission that meets these requirements. Disapproval does not start a mandatory sanctions clock. The EPA is deferring final action at this time on the disapprovals it proposed for Tennessee and Wyoming.

DATES: The effective date of this final rule is March 15, 2023.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2021–0663. Additional supporting materials associated with this final action are included in certain regional dockets. *See* the memo ''Regional Dockets Containing Additional Supporting Materials for Final Action on 2015 Ozone NAAQS Good Neighbor SIP Submissions'' in the docket for this action. All documents in the dockets are listed on the *https://www.regulations.gov* website. Although listed in the index, some information is not publicly available, *i.e.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the internet and will be publicly available only in hard copy form. Publicly available docket materials are available through *https://www.regulations.gov* or please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section for additional information.

FOR FURTHER INFORMATION CONTACT: General questions concerning this document should be addressed to Mr. Thomas Uher, Office of Air Quality Planning and Standards, Air Quality Policy Division, Mail Code C539–04, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (919) 541–5534; email address: *uher.thomas@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document ''we,'' ''us,'' and ''our'' refer to the EPA.

References to section numbers in roman numeral refer to sections of this preamble unless otherwise specified.

I. General Information

A. How can I get copies of this document and other related information?

The EPA established a Headquarters docket for this action under Docket ID No. EPA–HQ–OAR–2021–0663 and several regional dockets. All documents in the docket are listed in the electronic indexes, which, along with publicly available documents, are available at *https://www.regulations.gov.* Publicly available docket materials are also available in hard copy at the Air and Radiation Docket and Information Center, EPA/DC, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC. Some information in the docket may not be publicly available via the online docket due to docket file size restrictions, such as certain modeling files, or content (*e.g.,* CBI). For further information on the EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets.*

The EPA also established dockets in each of the EPA Regional offices to help support the proposals that are now being finalized in this national action. These include all public comments, technical support materials, and other files associated with this final action. Each regional docket contains a memorandum directing the public to the headquarters docket for this final action. While all documents in regional dockets are listed in the electronic indexes at *https://www.regulations.gov,* some information may not be publicly available via the online dockets due to docket file size restrictions, such as certain modeling files, or content (*e.g.,* CBI). Please contact the EPA Docket Center Services for further information.

B. How is the preamble organized?

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C. Where do I go if I have state-specific questions?

The following table identifies the states covered by this final action along with an EPA Regional office contact who can respond to questions about specific SIP submissions.

Regional offices	States
EPA Region 2: Kenneth Fradkin, Air and Radiation Division/Air Programs Branch, EPA Region 2, 290 Broadway, 25th Floor, New York, NY 10007.	New Jersey, New York.
EPA Region 3: Mike Gordon, Planning and Implementation Branch, EPA Region III, 1600 JFK Boulevard, Philadelphia, Pennsylvania 19103.	Maryland, West Virginia.
EPA Region 4: Evan Adams, Air and Radiation Division/Air Planning and Implementation Branch, EPA Region IV, 61 Forsyth Street SW, Atlanta, Georgia 30303.	Alabama, Kentucky, Mississippi.
EPA Region 5: Olivia Davidson, Air & Radiation Division/Air Programs Branch, EPA Region V, 77 W. Jackson Boulevard, Chicago, Illinois 60604–3511.	Indiana, Illinois, Michigan, Minnesota, Ohio, Wisconsin.
EPA Region 6: Sherry Fuerst, Air and Radiation Division, EPA Region 6, 1201 Elm Street, Suite 500, Dallas, Texas 75270.	Arkansas, Louisiana, Oklahoma, Texas.
EPA Region 7: William Stone, Air and Radiation Division, Air Quality Planning Branch, EPA Region VII, 11201 Renner Boulevard, Lenexa, Kansas 66219.	Missouri.
EPA Region 8: Adam Clark, Air and Radiation Division, EPA, Region VIII, Mailcode 8ARD–IO, 1595 Wynkoop Street, Denver, Colorado 80202.	Utah.
EPA Region 9: Tom Kelly, Air and Radiation Division, EPA Region IX, 75 Hawthorne St., San Francisco, California 94105.	California, Nevada.

II. Background and Overview

The following provides background for the EPA's final action on these SIP submissions related to the interstate transport requirements for the 2015 8-hour ozone NAAQS (2015 ozone NAAQS).

A. Description of Statutory Background

On October 1, 2015, the EPA promulgated a revision to the ozone NAAQS (2015 ozone NAAQS), lowering the level of both the primary and secondary standards to 0.070 parts per million (ppm) for the 8-hour standard.[1] Section 110(a)(1) of the CAA requires states to submit, within 3 years after promulgation of a new or revised standard, SIP submissions[2] meeting the applicable requirements of section 110(a)(2).[3] One of these applicable requirements is found in CAA section 110(a)(2)(D)(i)(I), otherwise known as the ''good neighbor'' or ''interstate transport'' provision, which generally requires SIPs to contain adequate provisions to prohibit in-state emissions activities from having certain adverse air quality effects on other states due to interstate transport of pollution. There are two so-called ''prongs'' within CAA section 110(a)(2)(D)(i)(I). A SIP for a new or revised NAAQS must contain adequate provisions prohibiting any source or other type of emissions activity within the state from emitting air pollutants in amounts that will significantly contribute to nonattainment of the NAAQS in another state (prong 1) or interfere with maintenance of the NAAQS in another state (prong 2). The EPA and states must give independent significance to prong 1 and prong 2 when evaluating downwind air quality problems under CAA section 110(a)(2)(D)(i)(I).[4]

On February 22, 2022, the EPA proposed to disapprove 19 good neighbor SIP submissions from the States of Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, West Virginia, and Wisconsin.[5] On May 24, 2022, the EPA proposed to disapprove four additional good neighbor SIP submissions from the States of California, Nevada, Utah, and Wyoming.[6] On October 25, 2022, the EPA proposed to disapprove a new good neighbor SIP submission from Alabama submitted on June 21, 2022.[7] The EPA is deferring action on the proposals related to the good neighbor SIP submissions from Tennessee and Wyoming at this time. As explained in the notifications of proposed disapproval, the EPA's justification for each of these proposals applies uniform, nationwide analytical methods, policy judgments, and interpretation with respect to the same CAA obligations, *i.e.,* implementation of good neighbor requirements under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS for states across the country. The EPA's final action is likewise based on this common core of determinations. As indicated at proposal, the EPA is taking a consolidated, single final action

[1] National Ambient Air Quality Standards for Ozone, Final Rule, 80 FR 65292 (October 26, 2015). Although the level of the standard is specified in the units of ppm, ozone concentrations are also described in parts per billion (ppb). For example, 0.070 ppm is equivalent to 70 ppb.

[2] The terms ''submission,'' ''revision,'' and ''submittal'' are used interchangeably in this document.

[3] SIP revisions that are intended to meet the applicable requirements of section 110(a)(1) and (2) of the CAA are often referred to as infrastructure SIPs and the applicable elements under CAA section 110(a)(2) are referred to as infrastructure requirements.

[4] *See North Carolina* v. *EPA,* 531 F.3d 896, 909–11 (D.C. Cir. 2008) (*North Carolina*).

[5] 87 FR 9545 (February 22, 2022) (Alabama, Mississippi, Tennessee); 87 FR 9798 (February 22, 2022) (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9838 (February 22, 2022) (Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin); 87 FR 9498 (February 22, 2022) (Kentucky); 87 FR 9484 (February 22, 2022) (New Jersey, New York); 87 FR 9463 (February 22, 2022) (Maryland); 87 FR 9533 (February 22, 2022) (Missouri); 87 FR 9516 (February 22, 2022) (West Virginia).

[6] 87 FR 31443 (May 24, 2022) (California); 87 FR 31485 (May 24, 2022) (Nevada); 87 FR 31470 (May 24, 2022) (Utah); 87 FR 31495 (May 24, 2022) (Wyoming).

[7] 87 FR 64412 (October 25, 2022) (Alabama). Alabama withdrew its original good neighbor SIP submission on April 21, 2022. *Id.* at 64419.

on the proposed SIP disapprovals.[8] Included in this document is final action on 2015 ozone NAAQS interstate transport SIPs addressing CAA section 110(a)(2)(D)(i)(I) for Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Texas, Utah, West Virginia, and Wisconsin. The 2015 ozone NAAQS interstate transport SIP submissions addressing CAA section 110(a)(2)(D)(i)(I) for Tennessee and Wyoming will be addressed in a separate action.

B. Description of the EPA's 4-Step Interstate Transport Framework

The EPA used a 4-step interstate transport framework (or 4-step framework) to evaluate each state's implementation plan submission addressing the interstate transport provision for the 2015 ozone NAAQS. The EPA has addressed the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) with respect to prior NAAQS in several regulatory actions, including the Cross-State Air Pollution Rule (CSAPR), which addressed interstate transport with respect to the 1997 ozone NAAQS as well as the 1997 and 2006 fine particulate matter standards,[9] the Cross-State Air Pollution Rule Update (CSAPR Update)[10] and the Revised CSAPR Update, both of which addressed the 2008 ozone NAAQS.[11]

Shaped through the years by input from state air agencies[12] and other stakeholders on EPA's prior interstate transport rulemakings and SIP actions,[13] as well as a number of court decisions, the EPA has developed and used the following 4-step interstate transport framework to evaluate a state's obligations to eliminate interstate transport emissions under the interstate transport provision for the ozone NAAQS: (1) Identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (*i.e.,* nonattainment and/or maintenance receptors); (2) identify states that impact those air quality problems in other (*i.e.,* downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis; (3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and (4) adopt permanent and enforceable measures needed to achieve those emissions reductions.

The general steps of this framework allow for some methodological variation, and this can be seen in the evolution of the EPA's analytical process across its prior rulemakings. This also means states have some flexibility in developing analytical methods within this framework (and may also attempt to justify an alternative framework altogether). The four steps of the framework simply provide a reasonable organization to the analysis of the complex air quality challenge of interstate ozone transport. As discussed further throughout this document, the EPA has organized its evaluation of the states' SIP submissions around this analytical framework (including the specific methodologies within each step as evolved over the course of the CSAPR rulemakings since 2011), but where states presented alternative approaches either to the EPA's methodological approaches within the framework, or organized their analysis in some manner that differed from it entirely, we have evaluated those analyses on their merits or, in some cases, identified why even if those approaches were acceptable, the state still does not have an approvable SIP submission as a whole.

C. Background on the EPA's Ozone Transport Modeling Information

In general, the EPA has performed nationwide air quality modeling to project ozone design values, which are used in combination with measured data to identify nonattainment and maintenance receptors at Step 1. To quantify the contribution of emissions from specific upwind states on 2023 ozone design values for the identified downwind nonattainment and maintenance receptors at Step 2, the EPA performed nationwide, state-level ozone source apportionment modeling for 2023. The source apportionment modeling projected contributions to ozone at receptors from precursor emissions of anthropogenic nitrogen oxides (NO_X) and volatile organic compounds (VOCs) in individual upwind states.

The EPA has released several documents containing projected design values, contributions, and information relevant to air agencies for evaluating interstate transport with respect to the 2015 ozone NAAQS. First, on January 6, 2017, the EPA published a notice of data availability (NODA) in which the Agency requested comment on preliminary interstate ozone transport data including projected ozone design values and interstate contributions for 2023 using a 2011 base year platform.[14] In the NODA, the EPA used the year 2023 as the analytic year for this preliminary modeling because that year aligns with the expected attainment year for Moderate ozone nonattainment areas for the 2015 ozone NAAQS.[15] On October 27, 2017, the EPA released a memorandum (October 2017 memorandum) containing updated modeling data for 2023, which incorporated changes made in response to comments on the NODA, and was intended to provide information to assist states' efforts to develop SIP submissions to address interstate transport obligations for the 2008 ozone NAAQS.[16] On March 27, 2018, the EPA issued a memorandum (March 2018 memorandum) noting that the same 2023 modeling data released in the

[8] In its proposals, the EPA stated ''The EPA may take a consolidated, single final action on all the proposed SIP disapproval actions with respect to obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. Should EPA take a single final action on all such disapprovals, this action would be nationally applicable, and the EPA would also anticipate, in the alternative, making and publishing a finding that such final action is based on a determination of nationwide scope or effect.'' E.g., 87 FR 9463, 9475 n.51.

[9] *See* Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 FR 48208 (August 8, 2011).

[10] Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 FR 74504 (October 26, 2016).

[11] In 2019, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) remanded CSAPR Update to the extent it failed to require upwind states to eliminate their significant contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). *Wisconsin* v. *EPA,* 938 F.3d 303, 313 (D.C. Cir. 2019) (*Wisconsin*). The Revised CSAPR Update for the 2008 Ozone NAAQS, 86 FR 23054 (April 30, 2021), responded to the remand of CSAPR Update in *Wisconsin* and the vacatur of a separate rule, the ''CSAPR Close-Out,'' 83 FR 65878 (December 21, 2018), in *New York* v. *EPA,* 781 F. App'x. 4 (D.C. Cir. 2019).

[12] *See* 63 FR 57356, 57361 (October 27, 1998).

[13] In addition to CSAPR rulemakings, other regional rulemakings addressing ozone transport include the ''NO_X SIP Call,'' 63 FR 57356 (October 27, 1998), and the ''Clean Air Interstate Rule'' (CAIR), 70 FR 25162 (May 12, 2005).

[14] *See* Notice of Availability of the Environmental Protection Agency's Preliminary Interstate Ozone Transport Modeling Data for the 2015 8-hour Ozone National Ambient Air Quality Standard (NAAQS), 82 FR 1733 (January 6, 2017).

[15] *See* 82 FR 1733, 1735 (January 6, 2017).

[16] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2008 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), October 27, 2017 (''October 2017 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0663 or at *https://www.epa.gov/interstate-air-pollution-transport/interstate-air-pollution-transport-memos-and-notices.*

October 2017 memorandum could also be useful for identifying potential downwind air quality problems with respect to the 2015 ozone NAAQS at Step 1 of the 4-step interstate transport framework.[17] The March 2018 memorandum also included the then newly available contribution modeling data for 2023 to assist states in evaluating their impact on potential downwind air quality problems for the 2015 ozone NAAQS under Step 2 of the 4-step interstate transport framework.[18] The EPA subsequently issued two more memoranda in August and October 2018, providing additional information to states developing interstate transport SIP submissions for the 2015 ozone NAAQS concerning, respectively, potential contribution thresholds that may be appropriate to apply in Step 2 of the 4-step interstate transport framework, and considerations for identifying downwind areas that may have problems maintaining the standard at Step 1 of the 4-step interstate transport framework.[19]

Following the release of the modeling data shared in the March 2018 memorandum, the EPA performed updated modeling using a 2016-based emissions modeling platform (*i.e.,* 2016v1). This emissions platform was developed under the EPA/Multi-Jurisdictional Organization (MJO)/state collaborative project.[20] This collaborative project was a multi-year joint effort by the EPA, MJOs, and states to develop a new, more recent emissions platform for use by the EPA and states in regulatory modeling as an improvement over the dated, 2011-based platform that the EPA had used to project ozone design values and contribution data provided in the 2017 and 2018 memoranda. The EPA used the 2016v1 emissions to project ozone design values and contributions for 2023. On October 30, 2020, in the notice of proposed rulemaking for the Revised CSAPR Update, the EPA released and accepted public comment on 2023 modeling that used the 2016v1 emissions platform.[21] Although the Revised CSAPR Update addressed transport for the 2008 ozone NAAQS, the projected design values and contributions from the 2016v1 platform were also useful for identifying downwind ozone problems and linkages with respect to the 2015 ozone NAAQS.[22]

Following the final Revised CSAPR Update, the EPA made further updates to the 2016-based emissions platform to include updated onroad mobile emissions from Version 3 of the EPA's Motor Vehicle Emission Simulator (MOVES) model (MOVES3)[23] and updated emissions projections for electric generating units (EGUs) that reflect the emissions reductions from the Revised CSAPR Update, recent information on plant closures, and other inventory improvements. The construct of the updated emissions platform, 2016v2, is described in the ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform,'' hereafter known as the 2016v2 Emissions Modeling TSD, and is included in Docket No. EPA–HQ–OAR–2021–0663. The EPA performed air quality modeling using the 2016v2 emissions to provide projections of ozone design values and contributions in 2023 that reflect the effects on air quality of the 2016v2 emissions platform. The results of the 2016v2 modeling were used by the EPA as part of the Agency's evaluation of state SIP submissions with respect to Steps 1 and 2 of the 4-step interstate transport framework at the proposal stage of this action. By using the 2016v2 modeling results, the EPA used the most current and technically appropriate information for the proposed rulemakings that were issued earlier in 2022.

The EPA invited and received comments on the 2016v2 emissions inventories and modeling that were used to support proposals related to 2015 ozone NAAQS interstate transport. (The EPA had earlier published the emissions inventories on its website in September of 2021 and invited initial feedback from states and other interested stakeholders.[24]) In response to these comments, the EPA made a number of updates to the 2016v2 inventories and model design to construct a 2016v3 emissions platform which was used to update the air quality modeling. The EPA made additional updates to its modeling in response to comments as well. The EPA is now using this updated modeling to inform its final action on these SIP submissions. Details on the air quality modeling and the methods for projecting design values and determining contributions in 2023 are described in Section III and in the TSD titled ''Air Quality Modeling TSD for the 2015 8-hour ozone NAAQS Transport SIP Final Actions'', hereafter known as the Final Action AQM TSD.[25] [26] Additional details related to the updated 2016v3 emissions platform are located in the TSD titled ''Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform,'' hereafter known as the 2016v3 Emissions Modeling TSD, included in Docket ID No. EPA–HQ–OAR–2021–0663.[27]

D. The EPA's Approach To Evaluating Interstate Transport SIPs for the 2015 Ozone NAAQS

The EPA is applying a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submissions for the 2015 ozone NAAQS under CAA section 110(a)(2)(D)(i)(I). These policy judgments conform with relevant case law and past agency practice as reflected in CSAPR and related rulemakings. Employing a nationally consistent approach is

[17] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), March 27, 2018 (''March 2018 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0663 or at *https://www.epa.gov/interstate-air-pollution-transport/interstate-air-pollution-transport-memos-and-notices.*

[18] The March 2018 memorandum, however, provided, ''While the information in this memorandum and the associated air quality analysis data could be used to inform the development of these SIPs, the information is not a final determination regarding states' obligations under the good neighbor provision. Any such determination would be made through notice-and-comment rulemaking.'' March 2018 memorandum at 2.

[19] *See* Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, August 31, 2018) (''August 2018 memorandum''); Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0663 or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.*

[20] The results of this modeling, as well as the underlying modeling files, are included in Docket No. EPA–HQ–OAR–2021–0663.

[21] *See* 85 FR 68964, 68981 (October 30, 2020).

[22] *See* the Air Quality Modeling Technical Support Document for the Final Revised Cross-State Air Pollution Rule Update, included in Docket No. EPA–HQ–OAR–2021–0663.

[23] 86 FR 1106. Additional details and documentation related to the MOVES3 model can be found at *https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves.*

[24] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

[25] *See* Final Action AQM TSD in Docket ID No. EPA–HQ–OAR–2021–0663

[26] References to section numbers in roman numeral refer to sections of this preamble unless otherwise specified, and references to section numbers in numeric form refer to the Response to Comments document for this final action included in the docket.

[27] *See* 2016v3 Emissions Modeling TSD in Docket ID No. EPA–HQ–OAR–2021–0663.

particularly important in the context of interstate ozone transport, which is a regional-scale pollution problem involving many smaller contributors. Effective policy solutions to the problem of interstate ozone transport going back to the NO_X SIP Call have necessitated the application of a uniform framework of policy judgments to ensure an ''efficient and equitable'' approach. *See EPA* v. *EME Homer City Generation, LP,* 572 U.S. 489, 519 (2014) (*EME Homer City*). Some comments on EPA's proposed SIP disapprovals claim the EPA is imposing non-statutory requirements onto SIPs or that the EPA must allow states to take inconsistent approaches to implementing good neighbor requirements. Both views are incorrect; the EPA's use of its longstanding framework to evaluate these SIP submissions reflects a reasonable and consistent approach to implementing the requirements of CAA section 110(a)(2)(D)(i)(I), while remaining open to alternative approaches states may present. These comments are further addressed in Section V and the Response to Comment (RTC) document contained in the docket for this action, Docket ID No. EPA–HQ–OAR–2021–0663.

In the March, August, and October 2018 memoranda, the EPA recognized that states may be able to establish alternative approaches to addressing their interstate transport obligations for the 2015 ozone NAAQS that vary from a nationally uniform framework. The EPA emphasized in these memoranda, however, that such alternative approaches must be technically justified and appropriate in light of the facts and circumstances of each particular state's submission.[28] In general, the EPA continues to believe that deviation from a nationally consistent approach to ozone transport must be substantially justified and have a well-documented technical basis that is consistent with CAA obligations and relevant case law. Where states submitted SIP submissions that rely on any such potential concepts as the EPA or others may have identified or suggested in the past, the EPA evaluated whether the state adequately justified the technical and legal basis for doing so. For example, the EPA has considered the arguments put forward by Alabama, Missouri, Ohio, Oklahoma, Texas, and Utah related to alternative methods of identifying receptors.[29] The EPA also has considered the arguments attempting to justify an alternative contribution threshold at Step 2 pursuant to the August 2018 memorandum made by Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Utah,[30] as well as criticisms of the 1 percent of the NAAQS contribution threshold made by Nevada and Ohio.[31] These topics are further addressed in Section V.B as well as the RTC document.

The EPA notes that certain potential concepts included in an attachment to the March 2018 memorandum require unique consideration, and these ideas do not constitute agency guidance with respect to interstate transport obligations for the 2015 ozone NAAQS. Attachment A to the March 2018 memorandum identified a ''Preliminary List of Potential Flexibilities'' that could potentially inform SIP development. However, the EPA made clear in both the March 2018 memorandum[32] and in Attachment A that the list of ideas was not endorsed by the Agency but rather ''comments provided in various forums'' on which the EPA sought ''feedback from interested stakeholders.''[33] Further, Attachment A stated, ''EPA is not at this time making any determination that the ideas discussed below are consistent with the requirements of the CAA, nor are we specifically recommending that states use these approaches.''[34] Attachment A to the March 2018 memorandum, therefore, does not constitute agency guidance, but was intended to generate further discussion around potential approaches to addressing ozone transport among interested stakeholders. To the extent states sought to develop or rely on one or more of these ideas in support of their SIP submissions, the EPA reviewed their technical and legal justifications for doing so.[35]

The remainder of this section describes the EPA's analytical framework with respect to analytic year, definition of nonattainment and maintenance receptors, selection of contribution threshold, and multifactor control strategy assessment.

1. Selection of Analytic Year

In general, the states and the EPA must implement the interstate transport provision in a manner ''consistent with the provisions of [title I of the CAA.]'' *See* CAA section 110(a)(2)(D)(i). This requires, among other things, that these obligations are addressed consistently with the timeframes for downwind areas to meet their CAA obligations. With respect to ozone NAAQS, under CAA section 181(a), this means obligations must be addressed ''as expeditiously as practicable'' and no later than the schedule of attainment dates provided in CAA section 181(a)(1).[36] Several D.C. Circuit court decisions address the issue of the relevant analytic year for the purposes of evaluating ozone transport air-quality problems. On September 13, 2019, the D.C. Circuit issued a decision in *Wisconsin,* remanding the CSAPR Update to the extent that it failed to require upwind states to eliminate their significant contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). *See* 938 F.3d 303, 313.

On May 19, 2020, the D.C. Circuit issued a decision in *Maryland* v. *EPA* that cited the *Wisconsin* decision in holding that the EPA must assess the impact of interstate transport on air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for the EPA's denial of a petition under CAA section 126(b) *Maryland* v.

[28] March 2018 memorandum at 3 (''EPA also notes that, in developing their own rules, states have flexibility to follow the familiar four-step transport framework (using EPA's analytical approach or somewhat different analytical approaches within this steps) or alternative framework, so long as their chosen approach has adequate technical justification and is consistent with the requirements of the CAA.''); August 2018 memorandum at 1 (''The EPA and air agencies should consider whether the recommendations in this guidance are appropriate for each situation.''); October 2018 memorandum at 1 (''Following the recommendations in this guidance does not ensure that EPA will approve a SIP revision in all instances where the recommendations are followed, as the guidance may not apply to the facts and circumstances underlying a particular SIP.'').

[29] 87 FR 64421–64422 (Alabama); 87 FR 9540–9541 (Missouri); 87 FR 9869–9870 (Ohio); 87 FR 9820–9822 (Oklahoma); 87 FR 9826–9829 (Texas); and 87 FR 31480–31481 (Utah).

[30] 87 FR 64423–64424 (Alabama); 87 FR 9806–9807 (Arkansas); 87 FR 9852–9853 (Illinois); 87 FR 9855–9856 (Indiana); 87 FR 9509–9510 (Kentucky); 87 FR 9815–9816 (Louisiana); 87 FR 9861–9862 (Michigan); 87 FR 9557 (Mississippi); 87 FR 9541–9544 (Missouri); 87 FR 9819 (Oklahoma); 87 FR 31478 (Utah).

[31] 87 FR 31492 (Nevada); 87 FR 9871 (Ohio).

[32] ''In addition, the memorandum is accompanied by Attachment A, which provides a preliminary list of potential flexibilities in analytical approaches for developing a good neighbor SIP that may warrant further discussion between EPA and states.'' March 2018 memorandum at 1.

[33] March 2018 memorandum, Attachment A at A–1.

[34] *Id.*

[35] E.g., 87 FR 64423–64425 (Alabama); 87 FR 31453–31454 (California); 87 FR 9852–9854 (Illinois); 87 FR 9859–9860 (Indiana); 87 FR 9508, 9515 (Kentucky); 87 FR 9861–9862 (Michigan); 87 FR 9869–9870 (Ohio); 87 FR 9798, 9818–9820 (Oklahoma); 87 FR 31477–31481 (Utah); 87 FR 9526–9527 (West Virginia).

[36] For attainment dates for the 2015 ozone NAAQS, refer to CAA section 181(a), 40 CFR 51.1303, and Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards, 83 FR 25776 (June 4, 2018, effective August 3, 2018).

EPA, 958 F.3d 1185, 1203–04 (D.C. Cir. 2020) (*Maryland*). The court noted that ''section 126(b) incorporates the Good Neighbor Provision,'' and, therefore, ''EPA must find a violation [of section 126] if an upwind source will significantly contribute to downwind nonattainment at the *next downwind attainment deadline.* Therefore, the agency must evaluate downwind air quality at that deadline, not at some later date.'' *Id.* at 1204 (emphasis added). The EPA interprets the court's holding in *Maryland* as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date,[37] which at the time of EPA's proposed and final actions on the SIPs addressed in this action is the Moderate area attainment date under CAA section 181 for ozone nonattainment. The Moderate area attainment date for the 2015 ozone NAAQS is August 3, 2024.[38] Thus, 2023 is now the appropriate year for analysis of interstate transport obligations for the 2015 ozone NAAQS, because the 2023 ozone season is the last relevant ozone season during which achieved emissions reductions in linked upwind states could assist downwind states with meeting the August 3, 2024, Moderate area attainment date for the 2015 ozone NAAQS.

The EPA recognizes that the attainment date for nonattainment areas classified as Marginal for the 2015 ozone NAAQS was August 3, 2021. Under the *Maryland* holding, any necessary emissions reductions to satisfy interstate transport obligations should have been implemented by no later than this date. At the time of the statutory deadline to submit interstate transport SIPs (October 1, 2018), many states relied upon the EPA's modeling of the year 2023, and no state provided an alternative analysis using a 2021 analytic year (or the prior 2020 ozone season). However, the EPA must act on SIP submissions using the information available at the time it takes such action, and it is now past 2021. In this circumstance, the EPA does not believe it would be appropriate to evaluate states' obligations under CAA section 110(a)(2)(D)(i)(I) as of an attainment date that is wholly in the past, because the Agency interprets the interstate transport provision as forward looking. *See* 86 FR 23054, 23074; *see also Wisconsin,* 938 F.3d at 322 (rejecting Delaware's argument that the EPA should have used an analytic year of 2011 instead of 2017). Consequently, in this proposal the EPA will use the analytical year of 2023 to evaluate each state's CAA section 110(a)(2)(D)(i)(I) SIP submission with respect to the 2015 ozone NAAQS.

2. Step 1 of the 4-Step Interstate Transport Framework

In Step 1, the EPA identifies monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS in the 2023 analytic year. Where the EPA's analysis shows that a site does not fall under the definition of a nonattainment or maintenance receptor, that site is excluded from further analysis under the EPA's 4-step interstate transport framework. For sites that are identified as a nonattainment or maintenance receptor in 2023, the EPA proceeds to the next step of the 4-step interstate transport framework by identifying which upwind states contribute to those receptors above the contribution threshold.

The EPA's approach to identifying ozone nonattainment and maintenance receptors in this action gives independent consideration to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of CAA section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina.*[39]

The EPA identifies nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the CSAPR Update, where the EPA defined nonattainment receptors as those areas that both currently measure nonattainment and that the EPA projects will be in nonattainment in the analytic year (*i.e.,* 2023).[40]

In addition, the EPA identifies a receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118, 136 (D.C. Cir. 2015) (*EME Homer City II*).[41] Specifically, the EPA identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that takes into account historical variability in air quality at that receptor. The variability in air quality was determined by evaluating the ''maximum'' future design value at each receptor based on a projection of the maximum measured design value over the relevant period. The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur. The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

Recognizing that nonattainment receptors are also, by definition, maintenance receptors, the EPA often uses the term ''maintenance-only'' to refer to those receptors that are not nonattainment receptors. Consistent with the concepts for maintenance receptors, as described earlier, the EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values. In addition, those

[37] The EPA notes that the court in *Maryland* did not have occasion to evaluate circumstances in which the EPA may determine that an upwind linkage to a downwind air quality problem exists at Steps 1 and 2 of the interstate transport framework by a particular attainment date, but for reasons of impossibility or profound uncertainty the Agency is unable to mandate upwind pollution controls by that date. *See Wisconsin,* 938 F.3d at 320. The D.C. Circuit noted in *Wisconsin* that upon a sufficient showing, these circumstances may warrant flexibility in effectuating the purpose of the interstate transport provision.

[38] *See* CAA section 181(a); 40 CFR 51.1303; Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards, 83 FR 25776 (June 4, 2018, effective August 3, 2018).

[39] *See North Carolina,* 531 F.3d at 910–11 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[40] *See* 81 FR 74504 (October 26, 2016). This same concept, relying on both current monitoring data and modeling to define nonattainment receptor, was also applied in CAIR. *See* 70 FR 25241, 25249 (January 14, 2005); *see also North Carolina,* 531 F.3d at 913–14 (affirming as reasonable the EPA's approach to defining nonattainment in CAIR).

[41] *See* 76 FR 48208 (August 8, 2011). The CSAPR Update and Revised CSAPR Update also used this approach. *See* 81 FR 74504 (October 26, 2016) and 86 FR 23054 (April 30, 2021).

monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance-only'' receptors, even if they are currently measuring nonattainment based on the most recent official design values.

As discussed further in Section III.B., in response to comments, the Agency has also taken a closer look at measured ozone levels at monitoring sites in 2021 and 2022 for the purposes of informing the identification of additional receptors in 2023. We find there is a basis to consider certain sites with elevated ozone levels that are not otherwise identified as receptors to be an additional type of maintenance-only receptor given the likelihood that ozone levels above the NAAQS could persist at those locations through at least 2023. We refer to these as violating-monitor maintenance-only receptors (''violating monitors''). For purposes of this action, we use this information only in a confirmatory way for states that are otherwise found to be linked using the modeling-based methodology. The EPA intends to take separate action to address states that are linked only to one or more violating-monitor receptors.

3. Step 2 of the 4-Step Interstate Transport Framework

In Step 2, the EPA quantifies the contribution of each upwind state to each receptor in the 2023 analytic year. The contribution metric used in Step 2 is defined as the average impact from each state to each receptor on the days with the highest ozone concentrations at the receptor based on the 2023 modeling. If a state's contribution value does not equal or exceed the threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb for the 2015 ozone NAAQS), the upwind state is not ''linked'' to a downwind air quality problem, and the EPA, therefore, concludes that the state does not contribute significantly to nonattainment or interfere with maintenance of the NAAQS in the downwind states. However, if a state's contribution equals or exceeds the 1 percent threshold, the state's emissions are further evaluated in Step 3, considering both air quality and cost as part of a multi-factor analysis, to determine what, if any, emissions might be deemed ''significant'' and, thus, must be eliminated pursuant to the requirements of CAA section 110(a)(2)(D)(i)(I).

In this final action, the EPA relies in the first instance on the 1 percent threshold for the purpose of evaluating a state's contribution to nonattainment or maintenance of the 2015 ozone NAAQS (*i.e.,* 0.70 ppb) at downwind receptors. This is consistent with the Step 2 approach that the EPA applied in CSAPR for the 1997 ozone NAAQS, which has subsequently been applied in the CSAPR Update and Revised CSAPR Update when evaluating interstate transport obligations for the 2008 ozone NAAQS, and in the EPA's proposals for this action. The EPA continues to find 1 percent to be an appropriate threshold. For ozone, as the EPA found in the CAIR, CSAPR, and CSAPR Update, a portion of the nonattainment problems from anthropogenic sources in the U.S. result from the combined impact of relatively small contributions, typically from multiple upwind states and, in some cases, substantially larger contributions from a subset of particular upwind states, along with contributions from in-state sources. The EPA's analysis shows that much of the ozone transport problem being analyzed in this action is still the result of the collective impacts of contributions from upwind states. Therefore, application of a consistent contribution threshold is necessary to identify those upwind states that should have responsibility for addressing their contribution to the downwind nonattainment and maintenance problems to which they collectively contribute. Continuing to use 1 percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows the EPA (and states) to apply a consistent framework to evaluate interstate emissions transport under the interstate transport provision from one NAAQS to the next. *See* 81 FR 74518; *see also* 86 FR 23085 (reviewing and explaining rationale from CSAPR, 76 FR 48237–38, for selection of 1 percent threshold).

The EPA's August 2018 memorandum recognizes that in certain circumstances, a state may be able to establish that an alternative contribution threshold of 1 ppb is justifiable. Where a state relies on this alternative threshold in their SIP submission, and where that state determined that it was not linked at Step 2 using the alternative threshold, the EPA evaluated whether the state provided a technically sound assessment of the appropriateness of using this alternative threshold based on the facts and circumstances underlying its application in the particular SIP submission. The states covered by this action that rely on a contribution threshold other than 1 percent of the NAAQS in their 2015 ozone NAAQS good neighbor SIP submission are Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Utah. Ohio also criticized the 1 percent of the NAAQS threshold, though it acknowledged it was linked above either a 1 percent of the NAAQS or 1 ppb contribution threshold. Nevada also criticized the 1 percent of the NAAQS contribution threshold, but ultimately relied on it to support its submission.

In the proposals for this action, the EPA evaluated each states' support for the use of an alternative threshold at Step 2 (*e.g.,* 1 ppb), and additionally shared its experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds at Step 2. The EPA solicited comment on the subject as it considered the appropriateness of rescinding the memorandum.[42] The EPA received numerous comments related to both the EPA's evaluation of SIP submissions relying on an alternative threshold, and the EPA's experience with alternative thresholds. The EPA is not, at this time rescinding the August 2018 memorandum; however, for purposes of evaluating contribution thresholds for the 2015 ozone NAAQS, the EPA continues to find the use of an alternative threshold problematic for the reasons stated at proposal. Regardless of the EPA's position on the August 2018 memorandum, the EPA continues to find that the arguments put forth in the SIP submissions of by Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Oklahoma, and Utah, as well as arguments in comments received on these actions, to be inadequate. *See* Section V.B.7 and the RTC Document for additional detail.

4. Step 3 of the 4-Step Interstate Transport Framework

Consistent with the EPA's longstanding approach to eliminating significant contribution and interference with maintenance, at Step 3, a multifactor assessment of potential emissions controls is conducted for states linked at Steps 1 and 2. The EPA's analysis at Step 3 in prior Federal actions addressing interstate transport requirements has primarily focused on an evaluation of cost-effectiveness of potential emissions controls (on a marginal cost-per-ton basis), the total emissions reductions that may be achieved by requiring such controls (if applied across all linked upwind states), and an evaluation of the air quality impacts such emissions reductions would have on the downwind receptors to which a state is linked; other factors may potentially be relevant if

[42] *See, e.g.,* 87 FR 9551.

adequately supported. In general, where the EPA's or state-provided alternative air quality and contribution modeling establishes that a state is linked at Steps 1 and 2, it will be insufficient at Step 3 for a state merely to point to its existing rules requiring control measures as a basis for SIP approval. In general, the emissions-reducing effects of all existing emissions control requirements are already reflected in the future year projected air quality results of the modeling for Steps 1 and 2. If the state is shown to still be linked to one or more downwind receptor(s) despite these existing controls, but that state believes it has no outstanding good neighbor obligations, the EPA expects the state to provide sufficient justification to support a conclusion by the EPA that the state has adequate provisions prohibiting ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will'' ''contribute significantly to nonattainment in, or interfere with maintenance by,'' any other State with respect to the NAAQS. *See* CAA section 110(a)(2)(D)(i)(I). While the EPA has not prescribed a particular method for this assessment, as many commenters note, the EPA expects states at a minimum to present a sufficient technical evaluation. This would typically include information on emissions sources, applicable control technologies, emissions reductions, costs, cost effectiveness, and downwind air quality impacts of the estimated reductions, before concluding that no additional emissions controls should be required.[43] The EPA responds to comment on issues related to Step 3 in Section V.B.8. and in the RTC document.

5. Step 4 of the 4-Step Interstate Transport Framework

At Step 4, states (or the EPA) develop permanent and federally-enforceable control strategies to achieve the emissions reductions determined to be necessary at Step 3 to eliminate significant contribution to nonattainment or interference with maintenance of the NAAQS.[44] For a state linked at Steps 1 and 2 to rely on an emissions control measure at Step 3 to address its interstate transport obligations, that measure must be included in the state's SIP so that it is permanent and federally enforceable. *See* CAA section 110(a)(2)(D) (''Each such [SIP] shall . . . contain adequate provisions. . . .''). *See also* CAA section 110(a)(2)(A); *Committee for a Better Arvin* v. *EPA,* 786 F.3d 1169, 1175–76 (9th Cir. 2015) (holding that measures relied on by a state to meet CAA requirements must be included in the SIP).

III. The EPA's Updated Air Quality and Contribution Analysis

As noted in Section II, the EPA relied in part on its 2016v2 emissions platform-based air quality modeling to support its proposed interstate transport actions taken in 2022. Following receipt of comments, the EPA updated this modeling, incorporating new information received to create the 2016v3 emissions inventory and making additional updates to improve model performance. Using the 2016v3 emissions inventory, the EPA evaluated modeling projections for air quality monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS.

This section presents a summary of the methodology and results of the 2016v3 modeling of 2023, along with the application of the EPA's Step 1 and Step 2 methodology for identifying receptors and upwind states that contribute to those receptors. We also explain that current measured ozone levels based on data for 2021 and preliminary data for 2022 at other monitoring sites (*i.e.,* monitoring sites that are not projected to be receptors in 2023 based on air quality modeling) confirm the likely continuation of elevated ozone levels in 2023 at these locations and confirm that nearly all upwind states in this action are also linked above 1 percent of the NAAQS to one or more of these monitors.

While all of this information compiled by the EPA (both the modeling and monitoring data) plays a critical role in the basis for this final action, the EPA has also thoroughly evaluated the modeling information and other analyses and arguments presented by the upwind states in their SIP submittals. Our evaluation of the states' analyses was generally set forth in the proposals, and the EPA in this final action has responded to comments on our evaluation of the various information and arguments made by states. The EPA's final decision to disapprove these states' SIP submittals is based on our evaluation of the entire record, recognizing that states possess the authority in the first instance to propose how they would address their significant contribution to air quality problems in other states. Nonetheless, as explained in the proposals, and in this document and supporting materials in the docket, we conclude that no state included in this action effectively demonstrated that it will not be linked to at least one air quality receptor in 2023, and none of these states' various arguments for alternative approaches ultimately present a satisfactory basis for the EPA to approve these states' SIP submissions.

A. Description of Air Quality Modeling for the Final Action

In this section, the Agency describes the air quality modeling performed consistent with Steps 1 and 2 of the 4-step interstate transport framework to (1) Identify locations where it expects nonattainment or maintenance problems with respect to the 2015 ozone NAAQS for the 2023 analytic year, and (2) quantify the contributions from anthropogenic emissions from upwind states to downwind ozone concentrations at monitoring sites projected to be in nonattainment or have maintenance problems for the 2015 ozone NAAQS in 2023. This section includes information on the air quality modeling platform used in support of the final SIP disapproval action with a focus on the base year and future base case emissions inventories. The EPA also provides the projection of 2023 ozone concentrations and the interstate contributions for 8-hour ozone. The Final Action AQM TSD in Docket ID No. EPA–HQ–OAR–2021–0663 contains more detailed information on the air quality modeling aspects supporting our final action on these SIP submissions.

1. Public Review of Air Quality Modeling Information for the Proposed Action

The EPA provided several opportunities to comment on the emissions modeling platform and air quality modeling results that were used for the proposed SIP submission actions. On September 20, 2021, the EPA publicly released via our web page updated emissions inventories (2016v2) and requested comment from states and

[43] Because no state included new enforceable emissions control measures in the submissions under review here, we focus our analysis on whether states justified that no additional controls were required. As examples of general approaches for how a Step 3 analysis could be conducted for their sources, states could look to the CSAPR Update, 81 FR 74504, 74539–51; CSAPR, 76 FR 48208, 48246–63; CAIR, 70 FR 25162, 25195–229; or the NO_X SIP Call, 63 FR 57356, 57399–405. *See also* Revised CSAPR Update, 86 FR 23054, 23086–23116. Consistently across these rulemakings, the EPA has developed emissions inventories, analyzed different levels of control stringency at different cost thresholds, and assessed resulting downwind air quality improvements.

[44] The EPA notes that any controls included in an approved SIP are federally-enforceable.

MJOs on these data.[45] In January 2022, the EPA released air quality modeling results including projected ozone design values and contributions from 2023 based on the 2016v2 emissions. At that time the EPA indicated its intent to use these data to support upcoming transport rulemakings. Then, on February 22, 2022, the EPA published proposed disapprovals for 19 interstate transport SIP submissions using the modeling data released in January 2022 and the emissions inventories shared in September 2021.[46] The EPA provided a 60-day comment period on these proposals. On May 24, 2022, the EPA proposed disapprovals for an additional four states' interstate transport SIP submissions using the same modeling platform, and provided a 62-day comment period.[47] The EPA provided a 30-day comment period beginning on October 25, 2022, on the proposed disapproval of Alabama's June 21, 2022, SIP submission, which relied on the same modeling platform as the other noted proposals.[48] In addition to its proposed disapprovals, the EPA also proposed approval of Iowa's, Arizona's, and Colorado's SIP submissions using the 2016v2 modeling and provided 30-day comment periods. 87 FR 9477 (February 22, 2022) (Iowa); 87 FR 37776 (June 24, 2022) (Arizona); and 87 FR 27050 (May 6, 2022) (Colorado).

2. Overview of Air Quality Modeling Platform

The EPA used version 3 of the 2016-based modeling platform (*i.e.,* 2016v3) for the air quality modeling for this final SIP disapproval action. This modeling platform includes 2016 base year emissions from anthropogenic and natural sources and future year projected anthropogenic emissions for 2023.[49] The emissions data contained in the 2016v3 platform represent an update to the 2016 version 2 inventories used for the proposal modeling.

The air quality modeling for this final disapproval action was performed for a modeling region (*i.e.,* modeling domain) that covers the contiguous 48 states using a horizontal resolution of 12 x 12 km. The EPA used the CAMx version 7.10 for air quality modeling which is the same model that the EPA used for the proposed rule air quality modeling.[50] Additional information on the 2016-based air quality modeling platform can be found in the Final Action AQM TSD.

Comments: Commenters noted that the 2016 base year summer maximum daily average 8-hour (MDA8) ozone predictions from the proposal modeling were biased low compared to the corresponding measured concentrations in certain locations. In this regard, commenters said that model performance statistics for a number of monitoring sites, particularly those in portions of the West and in the area around Lake Michigan, were outside the range of published performance criteria for normalized mean bias (NMB) and normalized mean error (NME) of less than plus or minus 15 percent and less than 25 percent, respectively.[51] Comments say the EPA must investigate the factors contributing to low bias and make necessary corrections to improve model performance in the modeling supporting final SIP actions. Some commenters said that the EPA should include NO_X emissions from lightning strikes and assess the treatment of other background sources of ozone to improve model performance for the final action. Additional information on the comments on model performance can be found in the RTC document for this final SIP disapproval action.

EPA Response: In response to these comments the EPA examined the temporal and spatial characteristics of model under prediction to investigate the possible causes of under prediction of MDA8 ozone concentrations in different regions of the U.S. in the proposal modeling. The EPA's analysis indicates that the under prediction was most extensive during May and June with less bias during July and August in most regions of the U.S. For example, in the Upper Midwest region model under prediction was larger in May and June compared to July through September. Specifically, the normalized mean bias for days with measured concentrations greater than or equal to 60 ppb improved from a 21.4 percent under prediction for May and June to a 12.6 percent under prediction in the period July through September. As described in the AQM TSD, the seasonal pattern in bias in the Upper Midwest region improves somewhat gradually with time from the middle of May to the latter part of June. In view of the seasonal pattern in bias in the Upper Midwest and in other regions of the U.S., the EPA focused its investigation of model performance on model inputs that, by their nature, have the largest temporal variation within the ozone season. These inputs include emissions from biogenic sources and lightning NO_X, and contributions from transport of international anthropogenic emissions and natural sources into the U.S. Both biogenic and lightning NO_X emissions in the U.S. dramatically increase from spring to summer.[52][53] In contrast, ozone transported into the U.S. from international anthropogenic and natural sources peaks during the period March through June, with lower contributions during July through September.[54][55] To investigate the impacts of the sources, the EPA conducted sensitivity model runs which focused on the effects on model performance of adding NO_X emissions from lightning strikes, using updated biogenic emissions, and using an alternative approach (described in more detail later in this section) for quantifying transport of ozone and precursor pollutants into the U.S. from international anthropogenic and natural sources. In the air quality modeling for proposal, the amount of transport from international sources was based on a simulation of the hemispheric version of the Community Multi-scale Air Quality

[45] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

[46] These proposals are listed in footnote 5 of this action.

[47] The EPA also relied on this same modeling data to support proposed Federal Implementation Plans (FIPs) resolving interstate transport obligations for 27 states for the 2015 ozone NAAQS. 87 FR 20036 (April 6, 2022). The EPA allowed 60 days to receive comments on the proposed FIP rule, including acceptance of comment on the 2016v2 emissions inventory-based modeling platform. The EPA then allowed for an additional 15 days via an extension of the comment period. 87 FR 29108 (May 12, 2022).

[48] 87 FR 64412, 64413.

[49] The 2016v3 platform also includes projected emissions for 2026. However, the 2026 data are not applicable and were not used in this final action.

[50] Ramboll Environment and Health, January 2021, *https://www.camx.com.*

[51] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[52] Guenther, A.B., 1997. Seasonal and spatial variations in natural volatile organic compound emissions. Ecol. Appl. 7, 34–45. *http://dx.doi.org/10.1890/1051-0761(1997)*007[0034:SASVIN]2.0.CO;2. Guenther, A., Hewitt, C.N., Erickson, D., Fall, R.

[53] Kang D, Mathur R, Pouliot GA, Gilliam RC, Wong DC. Significant ground-level ozone attributed to lightning-induced nitrogen oxides during summertime over the Mountain West States. NPJ Clim Atmos Sci. 2020 Jan 30;3:6. doi: 10.1038/s41612–020–0108–2. PMID: 32181370; PMCID: PMC7075249.

[54] Jaffe DA, Cooper OR, Fiore AM, Henderson BH, Tonnesen GS, Russell AG, Henze DK, Langford AO, Lin M, Moore T. Scientific assessment of background ozone over the U.S.: Implications for air quality management. Elementa (Wash DC). 2018;6(1):56. doi: 10.1525/elementa.309. PMID: 30364819; PMCID: PMC6198683.

[55] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, N. Possiel, G. Pouliot, B. Timin, K.W. Appel, 2019. Global Sources of North American Ozone. Presented at the 18th Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 21–23, 2019.

Model (H–CMAQ)[56] for 2016. The outputs from this hemispheric modeling were then used to provide boundary conditions for the national scale air quality modeling at proposal.[57] Overall, H–CMAQ tends to under predict daytime ozone concentrations at rural and remote monitoring sites across the U.S. during the spring of 2016 whereas the predictions from the GEOS-Chem global model[58] were generally less biased.[59] During the summer of 2016 both models showed varying degrees of over prediction with GEOS-Chem showing somewhat greater over prediction, compared to H–CMAQ. In view of those results, the EPA examined the impacts of using GEOS-Chem as an alternative to H–CMAQ for providing boundary conditions for the modeling supporting this final action.

For the lightning NO_X, biogenics, and GEOS-Chem sensitivity runs, the EPA reran the proposal modeling using each of these inputs, individually. Results from these sensitivity runs indicate that each of the three updates provides an improvement in model performance. However, by far the greatest improvement in modeling performance is attributable to the use of GEOS-Chem. In view of these results the EPA has included lightning NO_X emissions, updated biogenic emissions, and international transport from GEOS-Chem in the air quality modeling supporting final SIP actions. Details on the results of the individual sensitivity runs can be found in the AQM TSD. For the air quality modeling supporting final SIP actions, model performance based on days in 2016 with measured MDA8 ozone greater than or equal to 60 ppb is considerably improved (*i.e.,* less bias and error) compared to the proposal modeling in nearly all regions. For example, in the Upper Midwest, which includes monitoring sites along Lake Michigan, the normalized mean bias improved from a 19 percent under prediction to a 6.9 percent under prediction and in the Southwest region, which includes monitoring sites in Denver, Las Cruces, El Paso, and Salt Lake City, normalized mean bias improved from a 13.6 percent under prediction to a 4.8 percent under prediction.[60] In all regions, the normalized mean bias and normalized mean error statistics for high ozone days based on the modeling supporting final SIP actions are within the range of performance criteria benchmarks (*i.e.,* less than plus or minus 15 percent for normalized mean bias and less than 25 percent for normalized mean error).[61] Additional information on model performance information is provided in the AQM TSD. In summary, the EPA included emissions of lightning NO_X, as requested by commenters, and investigated and addressed concerns about model performance for the modeling supporting final SIP actions.

3. Emissions Inventories

The EPA developed emissions inventories to support air quality modeling for this final action, including emissions estimates for EGUs, non-EGU point sources (*i.e.,* stationary point sources), stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, other mobile sources, wildfires, prescribed fires, and biogenic emissions that are not the direct result of human activities. The EPA's air quality modeling relies on this comprehensive set of emissions inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements.

Prior to the modeling of air quality, the emissions inventories must be processed into a format that is appropriate for the air quality model to use. To prepare the emissions inventories for air quality modeling, the EPA processed the emissions inventories using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 4.9 to produce the gridded, hourly, speciated, model-ready emissions for input to the air quality model. Additional information on the development of the emissions inventories and on data sets used during the emissions modeling process are provided in the document titled ''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform,'' hereafter known as the ''2016v3 Emissions Modeling TSD.'' This TSD is available in the docket for this action.[62]

4. Foundation Emissions Inventory

The 2016v3 emissions platform is comprised of data from various sources including data developed using models, methods, and source datasets that became available in calendar years 2020 through 2022, in addition to data retained from the Inventory Collaborative 2016 version 1 (2016v1) Emissions Modeling Platform, released in October 2019. The 2016v1 platform was developed through a national collaborative effort between the EPA and state and local agencies along with MJOs. The 2016v2 platform used to support the proposed action included updated data, models and methods as compared to 2016v1. The 2016v3 platform includes updates implemented in response to comments along with other updates to the 2016v2 platform such as corrections and the incorporation of updated data sources that became available prior to the 2016v3 inventories being developed. Several commenters noted that the 2016v2 platform did not include NO_X emissions that resulted from lightning strikes. To address this, lightning NO_X emissions were computed and included in the 2016v3 platform.

For this final action, the EPA developed emissions inventories for the base year of 2016 and the projected year of 2023. The 2023 inventories represent changes in activity data and of predicted emissions reductions from on-the-books actions, planned emissions control installations, and promulgated Federal measures that affect anthropogenic emissions. The 2016 emissions inventories for the U.S. primarily include data derived from the 2017 National Emissions Inventory (2017

[56] Mathur, R., Gilliam, R., Bullock, O.R., Roselle, S., Pleim, J., Wong, D., Binkowski, F., and 1 Streets, D.: Extending the applicability of the community multiscale air quality model to 2 hemispheric scales: motivation, challenges, and progress. In: Steyn DG, Trini S (eds) Air 3 pollution modeling and its applications, XXI. Springer, Dordrecht, pp 175–179, 2012.

[57] Boundary conditions are the concentrations of pollutants along the north, east, south, and west boundaries of the air quality modeling domain. Boundary conditions vary in space and time and are typically obtained from predictions of global or hemispheric models. Information on how boundary conditions were developed for modeling supporting EPA's final SIP actions can be found in the AQM TSD.

[58] I. Bey, D.J. Jacob, R.M. Yantosca, J.A. Logan, B.D. Field, A.M. Fiore, Q. Li, H.Y. Liu, L.J. Mickley, M.G. Schultz. Global modeling of tropospheric chemistry with assimilated meteorology: model description and evaluation. J. Geophys. Res. Atmos., 106 (2001), pp. 23073–23095, 10.1029/2001jd000807.

[59] Henderson, B.H., P. Dolwick, C. Jang, A., Eyth, J. Vukovich, R. Mathur, C. Hogrefe, G. Pouliot, N. Possiel, B. Timin, K.W. Appel, 2022. Meteorological and Emission Sensitivity of Hemispheric Ozone and $PM_{2.5}$. Presented at the 21st Annual Conference of the UNC Institute for the Environment Community Modeling and Analysis System (CMAS) Center, October 17–19, 2022.

[60] A comparison of model performance from the proposal modeling to the final modeling for individual monitoring sites can be found in the docket for this final action.

[61] Christopher Emery, Zhen Liu, Armistead G. Russell, M. Talat Odman, Greg Yarwood & Naresh Kumar (2017) Recommendations on statistics and benchmarks to assess photochemical model performance, Journal of the Air & Waste Management Association, 67:5, 582–598, DOI: 10.1080/10962247.1265027.

[62] *See* Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform TSD, also available at *https://www.epa.gov/air-emissions-modeling/2016v3-platform.*

NEI)[63] and data specific to the year of 2016. The following sections provide an overview of the construct of the 2016v3 emissions and projections. The fire emissions were unchanged between the 2016v2 and 2016v3 emissions platforms. For the 2016v3 platform, the biogenic emissions were updated to use the latest available versions of the Biogenic Emissions Inventory System and associated land use data to help address comments related to a degradation in model performance in the 2016v2 platform as compared to the 2016v1 platform. Details on the construction of the inventories are available in the 2016v3 Emissions Modeling TSD. Details on how the EPA responded to comments related to emissions inventories are available in the RTC document for this action.

Development of emissions inventories for annual NO_X and sulfur dioxide (SO_2) emissions for EGUs in the 2016 base year inventory are based primarily on data from continuous emissions monitoring systems (CEMS) and other monitoring systems allowed for use by qualifying units under 40 CFR part 75, with other EGU pollutants estimated using emissions factors and annual heat input data reported to the EPA. For EGUs not reporting under part 75, the EPA used data submitted to the NEI by state, local, and tribal agencies. The final action inventories include updates made in response to comments on the proposed actions including the proposed SIP submission disapprovals and the proposed FIP. The Air Emissions Reporting Rule, (80 FR 8787; February 19, 2015), requires that Type A point sources large enough to meet or exceed specific thresholds for emissions be reported to the EPA via the NEI every year, while the smaller Type B point sources must only be reported to EPA every 3 years. In response to comments, emissions data for EGUs that did not have data submitted to the NEI specific to the year 2016 were filled in with data from the 2017 NEI. For more information on the details of how the 2016 EGU emissions were developed and prepared for air quality modeling, *see* the 2016v3 Emissions Modeling TSD.

The EPA projected 2023 baseline EGU emissions using version 6 of the Integrated Planning Model (IPM) (*www.epa.gov/airmarkets/powersector-modeling*). IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[64] The EPA relied on the same model platform as in the proposals but made substantial updates to reflect public comments on near-term fossil fuel market price volatility and updated fleet information reflecting Summer 2022 U.S. Energy Information Agency (EIA) 860 data, unit-level comments, and additional updates to the National Electric Energy Data System (NEEDS) inventory.

The IPM version 6—Updated Summer 2021 Reference Case incorporated recent updates through the summer 2022 to account for updated Federal and state environmental regulations (including Renewable Portfolio Standards (RPS), Clean Energy Standards (CES) and other state mandates), fleet changes (committed EGU retirements and new builds), electricity demand, technology cost and performance assumptions from recent data for renewables adopting from National Renewable Energy Lab (NREL's) Annual Technology Baseline 2020 and for fossil sources from the EIA's Annual Energy Outlook (AEO) 2020. Natural gas and coal price projections reflect data developed in fall 2020 but updated in summer 2022 to capture near-term price volatility and current market conditions. The inventory of EGUs provided as an input to the model was the NEEDS fall 2022 version and is available on the EPA's website.[65] This version of NEEDS reflects announced retirements and under construction new builds known as of early summer 2022. This projected base case accounts for the effects of the final Mercury and Air Toxics Standards rule, CSAPR, the CSAPR Update, the Revised CSAPR Update, New Source Review enforcement settlements, the final Effluent Limitation Guidelines (ELG) Rule, the Coal Combustion Residual (CCR) Rule, and other on-the-books Federal and state rules (including renewable energy tax credit extensions from the Consolidated Appropriations Act of 2021) through early 2021 impacting emissions of SO_2, NO_X, directly emitted particulate matter, carbon dioxide (CO_2), and power plant operations. It also includes final actions, up through the Summer 2022, the EPA has taken to implement the Regional Haze Rule and best available retrofit technology (BART) requirements. Documentation of IPM version 6 and NEEDS, along with updates, is in Docket ID No. EPA–HQ–OAR–2021–0663 and available online at *https://www.epa.gov/airmarkets/power-sector-modeling*.

Non-EGU point source emissions are mostly consistent with those in the proposal modeling except where they were updated in response to comments. Several commenters mentioned that point source emissions carried forward from 2014 NEI were not the best estimates of 2017 emissions. Thus, emissions sources in 2016v2 that had been projected from the 2014 NEI in the proposal were replaced with emissions based on the 2017 NEI. Point source emissions submitted to the 2016 NEI or to the 2016v1 platform development process specifically for the year 2016 were retained in 2016v3.

The 2023 non-EGU point source emissions were grown from 2016 to 2023 using factors based on AEO 2022 and reflect emissions reductions due to known national and local rules, control programs, plant closures, consent decrees, and settlements that could be computed as reductions to specific units by July 2022.

Aircraft emissions and ground support equipment at airports are represented as point sources and are based on adjustments to emissions in the January 2021 version of the 2017 NEI. The EPA developed and applied factors to adjust the 2017 airport emissions to 2016 and 2023 based on activity growth projected by the Federal Aviation Administration Terminal Area Forecast 2021,[66] the latest available version at the time the factors were developed.

[63] *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-technical-support-document-tsd.*

[64] Detailed information and documentation of the EPA's Base Case, including all the underlying assumptions, data sources, and architecture parameters can be found on the EPA's website at: *https://www.epa.gov/airmarkets/power-sector-modeling.*

[65] *Available* at *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

[66] *https://www.faa.gov/data_research/aviation/taf/.*

Emissions at rail yards were represented as point sources. The 2016 rail yard emissions are largely consistent with the 2017 NEI rail yard emissions. The 2016 and 2023 rail yard emissions were developed through the 2016v1 Inventory Collaborative process. Class I rail yard emissions were projected based on the AEO freight rail energy use growth rate projections for 2023 with the fleet mix assumed to be constant throughout the period.

The EPA made multiple updates to point source oil and gas emissions in response to comments. For the 2016v3 modeling, the point source oil and gas emissions for 2016 were based on the 2016v2 point inventory except that most 2014 NEI-based emissions were replaced with 2017 NEI emissions. Additionally, in response to comments, state-provided emissions equivalent to those in the 2016v1 platform were used for Colorado, and some New Mexico emissions were replaced with data backcast from 2020 to 2016. To develop inventories for 2023 for the 2016v3 platform, the year 2016 oil and gas point source inventories were first projected to 2021 values based on actual historical production data, then those 2021 emissions were projected to 2023 using regional projection factors based on AEO 2022 projections. This was an update from the 2016v2 approach in which actual data were used only through the year 2019, because 2021 data were not yet available. NO_X and VOC reductions resulting from co-benefits to New Source Performance Standards (NSPS) for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected, along with Natural Gas Turbine and Process Heater NSPS NO_X controls and Oil and Gas NSPS VOC controls. In some cases, year 2019 point source inventory data were used instead of the projected future year emissions except for the Western Regional Air Partnership (WRAP) states of Colorado, New Mexico, Montana, Wyoming, Utah, North Dakota, and South Dakota. The WRAP future year inventory [67] was used in these WRAP states in all future years except in New Mexico where the WRAP base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the recent oil and gas rule in the New Mexico Administrative code 20.2.50 [68] were also included. Details on the development of the projected point and nonpoint oil and gas emissions inventories are available in the 2016v3 Emissions Modeling TSD in Docket ID No. EPA–HQ–OAR–2021–0663.

Onroad mobile sources include exhaust, evaporative, and brake and tire wear emissions from vehicles that drive on roads, parked vehicles, and vehicle refueling. Emissions from vehicles using regular gasoline, high ethanol gasoline, diesel fuel, and electric vehicles were represented, along with buses that used compressed natural gas. The EPA developed the onroad mobile source emissions for states other than California using the EPA's Motor Vehicle Emissions Simulator (MOVES). MOVES3 was released in November 2020 and has been followed by some minor releases that improved the usage of the model but that do not have substantive impacts on the emissions estimates. For 2016v2, MOVES3 was run using inputs provided by state and local agencies through the 2017 NEI where available, in combination with nationally available data sets to develop a complete inventory. Onroad emissions were developed based on emissions factors output from MOVES3 run for the year 2016, coupled with activity data (*e.g.,* vehicle miles traveled and vehicle populations) representing the year 2016. The 2016 activity data were provided by some state and local agencies through the 2016v1 process, and the remaining activity data were derived from those used to develop the 2017 NEI. The onroad emissions were computed within SMOKE by multiplying emissions factors developed using MOVES with the appropriate activity data. Prior to computing the final action emissions for 2016, updates to some onroad inputs were made in response to comments and to implement corrections. Onroad mobile source emissions for California were consistent with the updated emissions data provided by the state for the final action.

The 2023 onroad emissions reflect projected changes to fuel properties and usage, along with the impact of the rules included in MOVES3 for each of those years. MOVES emissions factors for the year 2023 were used. A comprehensive list of control programs included for onroad mobile sources is available in the 2016v3 Emissions Modeling TSD. Year 2023 activity data for onroad mobile sources were provided by some state and local agencies, and otherwise were projected to 2023 by first projecting the 2016 activity to year 2019 based on county level vehicle miles traveled (VMT) from the Federal Highway Administration. The VMT were held flat from 2019 to 2021 to account for pandemic impacts, and then projected from 2021 to 2023 using AEO 2022-based factors.[69] Recent updates to inspection and maintenance programs in North Carolina and Tennessee were reflected in the MOVES inputs for the modeling supporting this final action. The 2023 onroad mobile emissions were computed within SMOKE by multiplying the respective emissions factors developed using MOVES with the year-specific activity data. Prior to computing the final action emissions for 2023, the EPA made updates to some onroad inputs in response to comments and to implement corrections.

The commercial marine vessel (CMV) emissions in the 2016 base case emissions inventory for this action were based on those in the 2017 NEI. Factors were applied to adjust the 2017 NEI emissions backward to represent emissions for the year 2016. The CMV emissions are consistent with the emissions for the 2016v1 platform CMV emissions released in February 2020 although, in response to comments, the EPA implemented an improved process for spatially allocating CMV emissions along state and county boundaries for the modeling supporting this final action.

The EPA developed nonroad mobile source emissions inventories (other than CMV, locomotive, and aircraft emissions) for 2016 and 2023 from monthly, county, and process level emissions output from MOVES3. Types of nonroad equipment include recreational vehicles, pleasure craft, and construction, agricultural, mining, and lawn and garden equipment.[70] The nonroad emissions for the final action were unchanged from those at the proposal. The nonroad mobile emissions control programs include reductions to locomotives, diesel engines, and recreational marine engines, along with standards for fuel sulfur content and evaporative emissions. A comprehensive list of

[67] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[68] *https://www.env.nm.gov/air-quality/ozone-draft-rule/* and *https://www.srca.nm.gov/parts/title20/20.002.0050.html.*

[69] VMT data for 2020 were the latest available at the time of final rule data development but were heavily impacted by the pandemic and unusable to project to 2023; in addition, it was determined that chaining factors based on AEO 2020 and AEO2021 obtain the needed factors led to unrealistic artifacts, thus only AEO 2022 data were used.

[70] Line haul locomotives are also considered a type of nonroad mobile source but the emissions inventories for locomotives were not developed using MOVES3. Year 2016 and 2023 locomotive emissions were developed through the 2016v1 process, and the year 2016 emissions are mostly consistent with those in the 2017 NEI. The projected locomotive emissions for 2023 were developed by applying factors to the base year emissions using activity data based on AEO freight rail energy use growth rate projections along with emissions rates adjusted to account for recent historical trends.

control programs included for mobile sources is available in the 2016v3 Emissions Modeling TSD.

For stationary nonpoint sources, some emissions in the 2016 base case emissions inventory come directly from the 2017 NEI, others were adjusted from the 2017 NEI to represent 2016 levels, and the remaining emissions including those from oil and gas, fertilizer, and solvents were computed specifically to represent 2016. Stationary nonpoint sources include evaporative sources, consumer products, fuel combustion that is not captured by point sources, agricultural livestock, agricultural fertilizer, residential wood combustion, fugitive dust, and oil and gas sources. The emissions sources derived from the 2017 NEI include agricultural livestock, fugitive dust, residential wood combustion, waste disposal (including composting), bulk gasoline terminals, and miscellaneous non-industrial sources such as cremation, hospitals, lamp breakage, and automotive repair shops. A recent method to compute solvent VOC emissions was used.[71]

Where comments were provided about projected control measures or changes in nonpoint source emissions, those inputs were first reviewed by the EPA. Those found to be based on reasonable data for affected emissions sources were incorporated into the projected inventories for 2023 to the extent possible. Where possible, projection factors based on the AEO used data from AEO 2022, the most recent AEO at the time available at the time the inventories were developed. Federal regulations that impact the nonpoint sources were reflected in the inventories. Adjustments for state fuel sulfur content rules for fuel oil in the Northeast were included along with solvent controls applicable within the northeast ozone transport region (OTR) states. Details are available in the 2016v3 Emissions Modeling TSD.

Nonpoint oil and gas emissions inventories for many states were developed based on outputs from the 2017 NEI version of the EPA Oil and Gas Tool using activity data for year 2016. Production-related emissions data from the 2017 NEI were used for Oklahoma, 2016v1 emissions were used for Colorado and Texas production-related sources to respond to comments. Data for production-related nonpoint oil and gas emissions in the States of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming were obtained from the WRAP baseline inventory.[72] A California Air Resources Board-provided inventory was used for 2016 oil and gas emissions in California. Nonpoint oil and gas inventories for 2023 were developed by first projecting the 2016 oil and gas inventories to 2021 values based on actual production data. Next, those 2021 emissions were projected to 2023 using regional projection factors by product type based on AEO 2022 projections. A 2017–2019 average inventory was used for oil and natural gas exploration emissions in 2023 everywhere except for California and in the WRAP states in which data from the WRAP future year inventory[73] were used. NO_X and VOC reductions that are co-benefits to the NSPS for RICE are reflected, along with Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls. The WRAP future year inventory was used for oil and natural gas production sources in 2023 except in New Mexico where the WRAP Base year emissions were projected using the EIA historical and AEO forecasted production data. Estimated impacts from the New Mexico Administrative Code 20.2.50 were included.

B. Air Quality Modeling To Identify Nonattainment and Maintenance Receptors

This section describes the air quality modeling and analyses that the EPA performed in Step 1 to identify locations where the Agency expects there to be nonattainment or maintenance receptors for the 2015 ozone NAAQS in 2023. Where the EPA's analysis shows that an area or site does not fall under the definition of a nonattainment or maintenance receptor in 2023, that site is excluded from further analysis under the EPA's good neighbor framework.

1. Approach for Identifying Receptors

In the proposed actions, the EPA applied the same approach used in the CSAPR Update and the Revised CSAPR Update to identify nonattainment and maintenance receptors for the 2008 ozone NAAQS.[74] The EPA's approach gives independent effect to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina*. Further, in its decision on the remand of CSAPR from the Supreme Court in the *EME Homer City II* case, the D.C. Circuit confirmed that the EPA's approach to identifying maintenance receptors in CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision.[75]

In the CSAPR Update and the Revised CSAPR Update, the EPA identified nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the NO_X SIP Call and CAIR, where the EPA defined nonattainment receptors as those areas that both currently monitor nonattainment and that the EPA projects will be in nonattainment in the future compliance year.

The Agency explained in the NO_X SIP Call and CAIR and then reaffirmed in the CSAPR Update that the EPA has the most confidence in our projections of nonattainment for those counties that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that receptor. The variability in air quality was determined by evaluating the ''maximum'' future design value at each receptor based on a projection of the maximum measured design value over the relevant period. The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, and air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur. The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

[71] *https://doi.org/10.5194/acp-21-5079-2021.*

[72] *http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf.*

[73] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[74] *See* 86 FR 23078–79.

[75] *EME Homer City II,* 795 F.3d at 136.

Therefore, applying this methodology for this action, the EPA assessed the magnitude of the maximum projected design values for 2023 at each receptor in relation to the 2015 ozone NAAQS and, where such a value exceeds the NAAQS, the EPA determined that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City II*.[76] That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.

Recognizing that nonattainment receptors are also, by definition, maintenance receptors, the EPA often uses the term ''maintenance-only'' to refer to receptors that are not also nonattainment receptors. Consistent with the concepts for maintenance receptors, as described earlier, the EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values. In addition, those monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance only'' receptors, even if they are currently measuring nonattainment based on the most recent official certified design values.[77]

Comment: The EPA received comments claiming that the projected design values for 2023 were biased low compared to recent measured data. Commenters noted that a number of monitoring sites that are projected to be below the NAAQS in 2023 based on the EPA's modeling for the proposed action are currently measuring nonattainment based on data from 2020 and 2021. One commenter requested that the EPA determine whether its past modeling tends to overestimate or underestimate actual observed design values. If EPA finds that the agency's model tends to underestimate future year design values, the commenter requests that EPA re-run its ozone modeling, incorporating parameters that account for this tendency.

EPA Response: In response to comments, the EPA compared the projected 2023 design values based on the proposal modeling to recent trends in measured data. As a result of this analysis, the EPA agrees that current data indicate that there are monitoring sites at risk of continued nonattainment in 2023 even though the model projected average and maximum design values at these sites are below the NAAQS (*i.e.,* these sites would not be modeling-based receptors at Step 1). While the EPA has confidence in the reliability of the modeling for projecting air quality conditions and contributions in future years, it would not be reasonable to ignore recent measured ozone levels in many areas that are clearly not fully consistent with certain concentrations in the Step 1 analysis for 2023. Therefore, the EPA has developed an additional maintenance-only receptor category, which includes what we refer to as ''violating monitor'' receptors, based on current ozone concentrations measured by regulatory ambient air quality monitoring sites.

Specifically, the EPA has identified monitoring sites with measured 2021 and preliminary 2022 design values *and* 4th high maximum daily 8-hour average (MDA8) ozone in both 2021 and 2022 (preliminary data) that exceed the NAAQS as having the greatest risk of continuing to have a problem attaining the standard in 2023. These criteria sufficiently consider measured air quality data so as to avoid including monitoring sites that have measured nonattainment data in recent years but could reasonably be anticipated to not have a nonattainment or maintenance problem in 2023, in line with our modeling results. Our methodology is intended only to identify those sites that have sufficiently poor ozone levels that there is clearly a reasonable expectation that an ozone nonattainment or maintenance problem will persist in the 2023 ozone season. Moreover, the 2023 ozone season is so near in time that recent measured ozone levels can be used to reasonably project whether an air quality problem is likely to persist. We view this approach to identifying additional receptors in 2023 as the best means of responding to the comments on this issue in this action, while also identifying all transport receptors.

For purposes of this action, we will treat these violating monitors as an additional type of maintenance-only receptor. We acknowledge that the traditional modeling plus monitoring methodology we used at proposal and in prior ozone transport rules would otherwise have identified such sites as being in attainment in 2023. Because our modeling did not identify these sites as receptors, we do not believe it is sufficiently certain that these sites will be in nonattainment that they should be considered nonattainment receptors. In the face of this uncertainty in the record, we regard our ability to consider such sites as receptors for purposes of good neighbor analysis under CAA section 110(a)(2)(D)(i)(I) to be a function of the requirement to prohibit emissions that interfere with maintenance of the NAAQS; even if an area may be projected to be in attainment, we have reliable information indicating that there is a clear risk that attainment will not in fact be achieved in 2023. Thus, our authority for treating these sites as receptors at Step 1 in 2023 flows from the responsibility in CAA section 110(a)(2)(i)(I) to prohibit emissions that interfere with maintenance of the NAAQS. *See, e.g., North Carolina,* 531 F.3d at 910–11 (failing to give effect to the interfere with maintenance clause ''provides no protection for downwind areas that, *despite EPA's predictions,* still find themselves struggling to meet NAAQS due to upwind interference . . . .'') (emphasis added). Recognizing that no modeling can perfectly forecast the future, and ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution,'' this approach in the Agency's judgement best balances the need to avoid both ''under-control'' and ''overcontrol,'' *EME Homer City,* 572 U.S. at 523. The EPA's analysis of these additional receptors further is explained in Section III.C.

However, because we did not propose to apply this expansion of the basis for regulation under the good neighbor provision receptor-identification methodology as the sole basis for finding an upwind state linked, in this action we are only using this receptor category on a confirmatory basis. That is, for states that we find linked based on our traditional modeling-based methodology in 2023, we find in this final analysis that the linkage at Step 2 is strengthened and confirmed if that state is also linked to one or more ''violating-monitor'' receptors. If a state is only linked to a violating-monitor receptor in this final analysis, we are deferring taking final action on that state's SIP submittal. This is the case for the State of Tennessee. Among the states that previously had their transport SIPs approved for the 2015 ozone NAAQS, the EPA has also identified a linkage to violating-monitor receptors for the State of Kansas. The EPA intends to further review its air quality modeling results and recent measured ozone levels, and we intend to address these states' good

[76] *EME Homer City II,* 795 F.3d at 136.

[77] *See https://www.epa.gov/air-trends/air-quality-design-values* for design value reports. At the time of this action, the most recent reports of certified design values available are for the calendar year 2021. The 2022 values are considered ''preliminary'' and therefore subject to change before certification.

neighbor obligations as expeditiously as practicable in a future action.

2. Methodology for Projecting Future Year Ozone Design Values

Consistent with the EPA's modeling guidance, the 2016 base year and future year air quality modeling results were used in a relative sense to project design values for 2023.[78] That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values up or down depending on the relative (percent) change in model predictions for each location. The EPA's modeling guidance recommends using measured ozone concentrations for the 5-year period centered on the base year as the air quality data starting point for future year projections. This average design value is used to dampen the effects of inter-annual variability in meteorology on ozone concentrations and to provide a reasonable projection of future air quality at the receptor under average conditions. In addition, the Agency calculated maximum design values from within the 5-year base period to represent conditions when meteorology is more favorable than average for ozone formation. Because the base year for the air quality modeling used in this final action is 2016, measured data for 2014–2018 (*i.e.,* design values for 2016, 2017, and 2018) were used to project average and maximum design values in 2023.

The ozone predictions from the 2016 and future year air quality model simulations were used to project 2016–2018 average and maximum ozone design values to 2023 using an approach similar to the approach in the EPA's guidance for attainment demonstration modeling. This guidance recommends using model predictions from the 3 x 3 array of grid cells surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site. However, the guidance also notes that an alternative array of grid cells may be used in certain situations where local topographic or geographical feature (*e.g.,* a large water body or a significant elevation change) may influence model response.

The 2016–2018 base period average and maximum design values were multiplied by the RRF to project each of these design values to 2023. In this manner, the projected design values are grounded in monitored data, and not the absolute model-predicted future year concentrations. Following the approach in the CSAPR Update and the Revised CSAPR Update, the EPA also projected future year design values based on a modified version of the ''3 x 3'' approach for those monitoring sites located in coastal areas. In this alternative approach, the EPA eliminated from the RRF calculations the modeling data in those grid cells that are dominated by water (*i.e.,* more than 50 percent of the area in the grid cell is water) and that do not contain a monitoring site (*i.e.,* if a grid cell is more than 50 percent water but contains an air quality monitor, that cell would remain in the calculation). The choice of more than 50 percent of the grid cell area as water as the criteria for identifying overwater grid cells is based on the treatment of land use in the Weather Research and Forecasting model (WRF). Specifically, in the WRF meteorological model those grid cells that are greater than 50% overwater are treated as being 100 percent overwater. In such cases the meteorological conditions in the entire grid cell reflect the vertical mixing and winds over water, even if part of the grid cell also happens to be over land with land-based emissions, as can often be the case for coastal areas. Overlaying land-based emissions with overwater meteorology may be representative of conditions at coastal monitors during times of on-shore flow associated with synoptic conditions or sea-breeze or lake-breeze wind flows. But there may be other times, particularly with off-shore wind flow, when vertical mixing of land-based emissions may be too limited due to the presence of overwater meteorology. Thus, for our modeling the EPA projected average and maximum design values at individual monitoring sites based on both the ''3 x 3'' approach as well as the alternative approach that eliminates overwater cells in the RRF calculation for near-coastal areas (*i.e.,* ''no water'' approach). The projected 2023 design values using both the ''3 x 3'' and ''no-water'' approaches are provided in the docket for this final action. Both approaches result in the same set of receptors in 2023. That is, monitoring sites that are identified as receptors in 2023 based on the ''3 x 3'' approach are also receptors based on the ''no water'' approach.

Consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS, the projected design values are evaluated after truncation to integers in units of ppb. Therefore, projected design values that are greater than or equal to 71 ppb are considered to be violating the 2015 ozone NAAQS. For those sites that are projected to be violating the NAAQS based on the average design values in 2023, the Agency examined the measured design values for 2021, which are the most recent official measured design values at the time of this final action.

As noted earlier, the Agency proposes to identify nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current measured air quality through 2021 and have projected average design values of 71 ppb or greater. Maintenance-only receptors include both: (1) Those sites with projected average design values above the NAAQS that are currently measuring clean data (*i.e.,* ozone design values below the level of the 2015 ozone NAAQS in 2021) and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 71 ppb or greater. In addition to the maintenance-only receptors, ozone nonattainment receptors are also maintenance receptors because the projected maximum design values for each of these sites is always greater than or equal to the average design value. Further, as explained previously in this section, the EPA identifies certain monitoring sites as ''violating monitor'' maintenance-only receptors based on 2021 and 2022 measured ozone levels.

The monitoring sites that the Agency projects to be nonattainment and maintenance receptors for the ozone NAAQS in the 2023 base case are used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of the 2015 ozone NAAQS as part of this final action.

3. 2023 Nonattainment and Maintenance-Only Receptors for the Final Action

In this section we provide information on modeling-based design values and measured data for monitoring sites identified as nonattainment or maintenance-only receptors in 2023 for this final action. Table III.B–1 of this action contains the 2016-centered base period average and maximum 8-hour ozone design values, the 2023 projected average and maximum design values and the measured 2021 design values for monitoring sites that are projected to be nonattainment receptors in 2023. Table III.B–2 of this action contains this same information for monitoring sites that are projected to be maintenance-only receptors in 2023, based on air quality modeling. Table III.B–3 of this action contains the 2023 projected average and maximum design values and 2021 design values and 4th high

[78] U.S. Environmental Protection Agency, 2018. Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze, Research Triangle Park, NC. *https://www.epa.gov/scram/state-implementation-plan-sip-attainment-demonstration-guidance.*

MDA8 ozone concentrations and preliminary 2020 design values and 4th high MDA8 ozone concentrations for monitoring sites identified as violating monitor maintenance-only receptors. The design values for all monitoring sites in the U.S. are provided in the docket for this action. Additional details on the approach for projecting average and maximum design values are provided in the AQM TSD.

TABLE III.B–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (PPB) AT PROJECTED NONATTAINMENT RECEPTORS [a]

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2021
060650016	CA	Riverside	79.0	80.0	72.2	73.1	78
060651016	CA	Riverside	99.7	101	91.0	92.2	95
080350004	CO	Douglas	77.3	78	71.3	71.9	83
080590006	CO	Jefferson	77.3	78	72.8	73.5	81
080590011	CO	Jefferson	79.3	80	73.5	74.1	83
090010017	CT	Fairfield	79.3	80	71.6	72.2	79
090013007	CT	Fairfield	82.0	83	72.9	73.8	81
090019003	CT	Fairfield	82.7	83	73.3	73.6	80
481671034	TX	Galveston	75.7	77	71.5	72.8	72
482010024	TX	Harris	79.3	81	75.1	76.7	74
490110004	UT	Davis	75.7	78	72.0	74.2	78
490353006	UT	Salt Lake	76.3	78	72.6	74.2	76
490353013	UT	Salt Lake	76.5	77	73.3	73.8	76
551170006	WI	Sheboygan	80.0	81	72.7	73.6	72

[a] 2016-centered base period average design values and projected average and maximum design values are reported with 1 digit to the right of the decimal, as recommended in the EPA's modeling guidance. The 2016 maximum design values and 2021 design values are truncated to integer values consistent with ozone design value reporting convention in appendix U of 40 CFR part 50.

TABLE III.B–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2021 DESIGN VALUES (PPB) AT PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2021
040278011	AZ	Yuma	72.3	74	70.4	72.1	67
080690011	CO	Larimer	75.7	77	70.9	72.1	77
090099002	CT	New Haven	79.7	82	70.5	72.6	82
170310001	IL	Cook	73.0	77	68.2	71.9	71
170314201	IL	Cook	73.3	77	68.0	71.5	74
170317002	IL	Cook	74.0	77	68.5	71.3	73
350130021	NM	Dona Ana	72.7	74	70.8	72.1	80
350130022	NM	Dona Ana	71.3	74	69.7	72.4	75
350151005	NM	Eddy	69.7	74	69.7	74.1	77
350250008	NM	Lea	67.7	70	69.8	72.2	66
480391004	TX	Brazoria	74.7	77	70.4	72.5	75
481210034	TX	Denton	78.0	80	69.8	71.6	74
481410037	TX	El Paso	71.3	73	69.8	71.4	75
482010055	TX	Harris	76.0	77	70.9	71.9	77
482011034	TX	Harris	73.7	75	70.1	71.3	71
482011035	TX	Harris	71.3	75	67.8	71.3	71
530330023	WA	King	73.3	77	67.6	71.0	64
550590019	WI	Kenosha	78.0	79	70.8	71.7	74
551010020	WI	Racine	76.0	78	69.7	71.5	73

In total, in 2023 there are a total of projected 33 modeling-based receptors nationwide including 14 nonattainment receptors in 9 different counties and 19 maintenance-only receptors in 13 additional counties (Harris County, TX, has both nonattainment and maintenance-only receptors).

As shown in Table III.B–3 of this action, there are 49 monitoring sites that are identified as ''violating-monitor'' maintenance-only receptors in 2023.As noted earlier in this section, the EPA uses the approach of considering ''violating-monitor'' maintenance-only receptors as confirmatory of the proposal's identification of receptors and does not implicate additional linked states in this final action, Rather, using this approach serves to strengthen the analytical basis for our Step 2 findings by establishing that many upwind states covered in this action are also projected to contribute above 1 percent of the NAAQS to these additional ''violating monitor'' maintenance-only receptors.

TABLE III.B–3—AVERAGE AND MAXIMUM 2023 BASE CASE 8-HOUR OZONE, AND 2021 AND PRELIMINARY 2022 DESIGN VALUES (PPB) AND 4TH HIGH CONCENTRATIONS AT VIOLATING MONITORS [a]

Monitor ID	State	County	2023 average	2023 maximum	2021	2022 P	2021 4th high	2022 P 4th high
40070010	AZ	Gila	67.9	69.5	77	76	75	74
40130019	AZ	Maricopa	69.8	70.0	75	77	78	76
40131003	AZ	Maricopa	70.1	70.7	80	80	83	78
40131004	AZ	Maricopa	70.2	70.8	80	81	81	77
40131010	AZ	Maricopa	68.3	69.2	79	80	80	78
40132001	AZ	Maricopa	63.8	64.1	74	78	79	81
40132005	AZ	Maricopa	69.6	70.5	78	79	79	77
40133002	AZ	Maricopa	65.8	65.8	75	75	81	72
40134004	AZ	Maricopa	65.7	66.6	73	73	73	71
40134005	AZ	Maricopa	62.3	62.3	73	75	79	73
40134008	AZ	Maricopa	65.6	66.5	74	74	74	71
40134010	AZ	Maricopa	63.8	66.9	74	76	77	75
40137020	AZ	Maricopa	67.0	67.0	76	77	77	75
40137021	AZ	Maricopa	69.8	70.1	77	77	78	75
40137022	AZ	Maricopa	68.2	69.1	76	78	76	79
40137024	AZ	Maricopa	67.0	67.9	74	76	74	77
40139702	AZ	Maricopa	66.9	68.1	75	77	72	77
40139704	AZ	Maricopa	65.3	66.2	74	77	76	76
40139997	AZ	Maricopa	70.5	70.5	76	79	82	76
40218001	AZ	Pinal	67.8	69.0	75	76	73	77
80013001	CO	Adams	63.0	63.0	72	77	79	75
80050002	CO	Arapahoe	68.0	68.0	80	80	84	73
80310002	CO	Denver	63.6	64.8	72	74	77	71
80310026	CO	Denver	64.5	64.8	75	77	83	72
90079007	CT	Middlesex	68.7	69.0	74	73	78	73
90110124	CT	New London	65.5	67.0	73	72	75	71
170310032	IL	Cook	67.3	69.8	75	75	77	72
170311601	IL	Cook	63.8	64.5	72	73	72	71
181270024	IN	Porter	63.4	64.6	72	73	72	73
260050003	MI	Allegan	66.2	67.4	75	75	78	73
261210039	MI	Muskegon	67.5	68.4	74	79	75	82
320030043	NV	Clark	68.4	69.4	73	75	74	74
350011012	NM	Bernalillo	63.8	66.0	72	73	76	74
350130008	NM	Dona Ana	65.6	66.3	72	76	79	78
361030002	NY	Suffolk	66.2	68.0	73	74	79	74
390850003	OH	Lake	64.3	64.6	72	74	72	76
480290052	TX	Bexar	67.1	67.8	73	74	78	72
480850005	TX	Collin	65.4	66.0	75	74	81	73
481130075	TX	Dallas	65.3	66.5	71	71	73	72
481211032	TX	Denton	65.9	67.7	76	77	85	77
482010051	TX	Harris	65.3	66.3	74	73	83	72
482010416	TX	Harris	68.8	70.4	73	73	78	71
484390075	TX	Tarrant	63.8	64.7	75	76	76	77
484391002	TX	Tarrant	64.1	65.7	72	77	76	80
484392003	TX	Tarrant	65.2	65.9	72	72	74	72
484393009	TX	Tarrant	67.5	68.1	74	75	75	75
490571003	UT	Weber	69.3	70.3	71	74	77	71
550590025	WI	Kenosha	67.6	70.7	72	73	72	71
550890008	WI	Ozaukee	65.2	65.8	71	72	72	72

[a] 2022 preliminary design values are based on 2022 measured MDA8 concentrations provided by state air agencies to the EPA's Air Quality System (AQS), as of January 3, 2023.

C. Air Quality Modeling To Quantify Upwind State Contributions

This section documents the procedures the EPA used to quantify the impact of emissions from specific upwind states on ozone design values in 2023 for the identified downwind nonattainment and maintenance receptors. The EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on downwind nonattainment and maintenance receptors for 8-hour ozone. CAMx employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations. The benefit of the photochemical model source apportionment technique is that all modeled ozone at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources.

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique [79] to quantify the contribution of 2023 NO_X and VOC emissions from all sources in each state to the corresponding projected ozone design values in 2023 at

[79] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

air quality monitoring sites. The CAMx OSAT/APCA model run was performed for the period May 1 through September 30 using the projected future base case emissions and 2016 meteorology for this time period. In the source apportionment modeling the Agency tracked (*i.e.,* tagged) the amount of ozone formed from anthropogenic emissions in each state individually as well as the contributions from other sources (*e.g.,* natural emissions).

In the state-by-state source apportionment model run, the EPA tracked the ozone formed from each of the following tags:

• States—anthropogenic NO_X emissions and VOC emissions from individual state (emissions from all anthropogenic sectors in a given state were combined);

• Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);

• Boundary Concentrations—concentrations transported into the air quality modeling domain;

• Tribes—the emissions from those tribal lands for which the Agency has point source inventory data emissions modeling platform (EPA did not model the contributions from individual tribes);

• Canada and Mexico—anthropogenic emissions from those sources in the portions of Canada and Mexico included within the modeling domain (the EPA did not model the contributions from Canada and Mexico separately);

• Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and

• Offshore—combined emissions from offshore marine vessels and offshore drilling platforms within the modeling domain.

The contribution modeling provided contributions to ozone from anthropogenic NO_X and VOC emissions in each state, individually. The contributions to ozone from chemical reactions between biogenic NO_X and VOC emissions were modeled and assigned to the ''biogenic'' category. The contributions from wildfire and prescribed fire NO_X and VOC emissions were modeled and assigned to the ''fires'' category. That is, the contributions from the ''biogenic'' and ''fires'' categories are not assigned to individual states nor are they included in the state contributions.

For the Step 2 analysis, the EPA calculated a contribution metric that considers the average contribution on the 10 highest ozone concentration days (*i.e.,* top 10 days) in 2023 using the same approach as the EPA used in the proposed action and in the Revised CSAPR Update.[80] This average contribution metric is intended to provide a reasonable representation of the contribution from individual states to projected future year design values, based on modeled transport patterns and other meteorological conditions generally associated with modeled high ozone concentrations at the receptor. An average contribution metric constructed in this manner ensures the magnitude of the contributions is directly related to the magnitude of the ozone design value at each site.

The analytic steps for calculating the contribution metric for the 2023 analytic year are as follows:

(1) Calculate the 8-hour average contribution from each source tag to individual ozone monitoring site for the time period of the 8-hour daily maximum modeled concentrations in 2023;

(2) Average the contributions and average the concentrations for the top 10 modeled ozone concentration days in 2023;

(3) Divide the average contribution by the corresponding average concentration to obtain a Relative Contribution Factor (RCF) for each monitoring site;

(4) Multiply the 2023 average design value by the 2023 RCF at each site to produce the average contribution metric values in 2023;[81]

(5) Truncate the average contribution metric values to two digits to the right of the decimal for comparison to the 1 percent of the NAAQS screening threshold (0.70 ppb)

The resulting contributions from each tag to each monitoring site in the U.S. for 2023 can be found in the docket for this final action. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the AQM TSD. The EPA's response to comments on the method for calculating the contribution metric can be found in the RTC document for this final action.

The largest contribution from each state that is the subject of this final action to modeled 8-hour ozone nonattainment and modeling-based maintenance receptors in downwind states in 2023 are provided in Table III.C–1 of this action. The largest contribution from each state to the additional ''violating monitor'' maintenance-only receptors is provided in Table III.C–2 of this action. All states that are linked to one or more nonattainment or maintenance-only receptors are also linked to one or more violating monitor maintenance receptors, except for Minnesota.

TABLE III.C–1—LARGEST CONTRIBUTION BY STATE TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023 (ppb)

Upwind state	Largest contribution to a downwind nonattainment receptor	Largest contribution to a downwind maintenance-only receptor
Alabama	0.75	0.65
Arkansas	0.94	1.21
California	35.27	6.31
Illinois	13.89	19.09
Indiana	8.90	10.03
Kentucky	0.84	0.79
Louisiana	9.51	5.62

[80] The use of daily contributions on the top 10 concentration days for calculating the average contribution metric is designed to be consistent with the method specified in the modeling guidance in terms of the number of days to use when projecting future year design values.

[81] Note that a contribution metric value was not calculated for any receptor at which there were fewer than 5 days with model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in 2023. Eliminating from the Step 2 evaluation any receptors for which the modeling does not meet this criterion ensures that upwind state contributions are based on the days with the highest ozone projections. This criterion is consistent with the criterion for projecting design values, as recommended in the EPA's modeling guidance. In the modeling for this final action, the monitoring site in Seattle, Washington (530330023), was the only receptor that did not meet this criterion.

TABLE III.C–1—LARGEST CONTRIBUTION BY STATE TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023 (ppb)—Continued

Upwind state	Largest contribution to a downwind nonattainment receptor	Largest contribution to a downwind maintenance-only receptor
Maryland	1.13	1.28
Michigan	1.59	1.56
Minnesota	0.36	0.85
Mississippi	1.32	0.91
Missouri	1.87	1.39
Nevada	1.11	1.13
New Jersey	8.38	5.79
New York	16.10	11.29
Ohio	2.05	1.98
Oklahoma	0.79	1.01
Texas	1.03	4.74
Utah	1.29	0.98
West Virginia	1.37	1.49
Wisconsin	0.21	2.86

TABLE III.C–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE "VIOLATING MONITOR" MAINTENANCE-ONLY RECEPTORS (ppb)

Upwind State	Largest contribution to a downwind violating monitor maintenance-only receptor
Alabama	0.79
Arkansas	1.16
California	6.97
Illinois	16.53
Indiana	9.39
Kentucky	1.57
Louisiana	5.06
Maryland	1.14
Michigan	3.47
Minnesota	0.64
Mississippi	1.02
Missouri	2.95
Nevada	1.11
New Jersey	8.00
New York	12.08
Ohio	2.25
Oklahoma	1.57
Texas	3.83
Utah	1.46
West Virginia	1.79
Wisconsin	5.10

IV. Summary of Bases for Disapproval

As explained in Section II, the EPA relies on the 4-step interstate transport framework to evaluate obligations under CAA section 110(a)(2)(D)(i)(I). At proposal, the EPA used this framework to guide its evaluation of each state's SIP submission. While the EPA used this framework to maintain a nationally consistent and equitable approach to interstate transport, the contents of each individual state's submission were evaluated on their own merits, and the EPA considered the facts and information, including information from the Agency, available to the state at the time of its submission, in addition to more recent air quality and contribution information. Here we provide a brief, high level overview of the SIP submissions and the EPA's evaluation and key bases for disapproval. These summaries are presented for ease of reference and to direct the public to the most relevant portions of the proposals and final rule record for further information. The full basis for the EPA's disapprovals is available in relevant **Federal Register** notifications of proposed disapproval for each state, in the technical support documents informing the proposed and final action, and in the responses to comments in Section V and the RTC document. In general, except as otherwise noted, the comments and updated air quality information did not convince the Agency that a change from proposal was warranted for any state. The exceptions are that the EPA is deferring action at this time on the proposed disapprovals for Tennessee and Wyoming. Further, the EPA is finalizing partial approvals of prong 1 (''significant contribution to nonattainment'') for Minnesota and Wisconsin because they are linked only to maintenance-only receptors; the EPA is finalizing a partial disapproval with respect to prong 2 (''interference with maintenance'') obligations for these two states.

A. Alabama

In the 2016v3 modeling, Alabama is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor. It is also linked to one violating-monitor maintenance-only receptor. Its highest-level contribution is 0.75 ppb to Galveston County, Texas (AQS Site ID 481671034).[82] A full summary of Alabama's June 21, 2022, SIP submission, as well as Alabama's previous submission history, was provided in the proposed SIP submission disapproval.[83] In its submission, Alabama advocated for discounting maintenance receptors through use of historical data trends. The EPA finds Alabama's approach is not adequately justified.[84] The EPA disagrees with Alabama's assessment of the 2016v2 modeling,[85] and further responds to comments on model performance in Section III. The EPA disagrees with Alabama's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2,[86] and further addresses the relevance of ''significant impact levels'' within the Prevention of Significant Deterioration program (''PSD SILs'') in Section V.B.6. The EPA found technical flaws in Alabama's back trajectory analysis.[87] The State did not conduct an adequate Step 3 analysis, and the EPA identified several unsupported assertions in the SIP submission.[88] Alabama also argued in its SIP submission that it had already implemented all cost-effective controls. However, the State included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[89] The EPA further addresses arguments related to

[82] The highest-magnitude downwind contribution from each state is based on the contributions to modeling-based receptors and does not consider the contributions to violating-monitor maintenance-only receptors. Each state's maximum contribution to downwind violating-monitor maintenance-only receptors is available in the Final Action AQM TSD.

[83] 87 FR 64419–64421.

[84] Id. at 64421–64422.

[85] Id. at 64422–64423.

[86] Id. at 64423–64424.

[87] Id. at 64424–64425.

[88] Id. at 64425–64426.

[89] Id.

mobile sources in Section V.C.1.[90] Additionally, as explained in Section V.B.9,[91] reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3. The State included no permanent and enforceable emissions controls in its SIP submission.[92] We provide further response to comments regarding Alabama's SIP submission in the RTC document. The EPA is finalizing disapproval of Alabama's interstate transport SIP submission for the 2015 ozone NAAQS.

B. Arkansas

In the 2016v3 modeling, Arkansas is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor and five maintenance-only receptors. It is also linked to seven violating-monitor maintenance-only receptor. Its highest-level contribution is 1.21 ppb to Brazoria County Texas (AQS Site ID 480391004). A full summary of Arkansas's October 10, 2019, SIP submission was provided in the proposed SIP submission disapproval.[93] The EPA disagrees with Arkansas's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2, and further addresses the relevance of PSD SILs in Section V.B.6.[94] The EPA also found technical flaws in Arkansas's ''consistent and persistent'' claims and back trajectory analysis,[95] and legal flaws in the state's arguments related to relative contribution.[96] The State did not conduct an adequate Step 3 analysis.[97] Arkansas argued in its SIP submission that it had already implemented all cost-effective controls. However, the State included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[98] Further, the State's reliance on the cost-effectiveness thresholds in the CSAPR and CSAPR Update is insufficient for the more protective 2015 ozone NAAQS.[99] The State included no permanent and enforceable controls in its SIP submission.[100] We provide further response to comments regarding Arkansas's SIP submission in the RTC document. The EPA is finalizing disapproval of Arkansas's interstate transport SIP submission for the 2015 ozone NAAQS.

C. California

In the 2016v3 modeling, California is projected to be linked above 1 percent of the NAAQS to eight nonattainment receptors and four maintenance-only receptors. It is also linked to 26 violating-monitor maintenance-only receptor. Its highest-level contribution is 35.27 ppb to the nonattainment receptor located on the Morongo Band of Missions Indians reservation (AQS Site ID 060651016).[101] A full summary of California's October 1, 2018, SIP submission was provided in the proposed SIP submission disapproval.[102] The EPA found technical and legal flaws in California's geographic, meteorological, wildfire, and trajectories analysis, and the State's arguments related to local, international, and non-anthropogenic emissions.[103] The EPA further addresses the topic of international emissions in Section V.C.2. The State did not conduct an adequate Step 3 analysis.[104] California in its SIP submission argued that it had already implemented all cost-effective controls. However, California provided an insufficient evaluation of additional control opportunities to support such a conclusion.[105] Further, the State's reliance on the cost-effectiveness threshold in the CSAPR Update is insufficient for the more protective 2015 ozone NAAQS.[106] California included no permanent and enforceable emissions controls in its SIP submission [107] and argued that interstate transport is fundamentally different in the western U.S. than in the eastern U.S., to which the EPA responds in Section V.C.3.[108] We provide further response to comments regarding California's SIP submission in the RTC document. The EPA is finalizing disapproval of California's interstate transport SIP submission for the 2015 ozone NAAQS.

D. Illinois

In the 2016v3 modeling, Illinois is projected to be linked above 1 percent of the NAAQS to two nonattainment receptors and three maintenance-only receptors. It is also linked to six violating-monitor maintenance-only receptor. Its highest-level contribution is 19.09 ppb to Kenosha County, Wisconsin (AQS Site ID 550590019). A full summary of Illinois's May 21, 2019, SIP submission was provided in the proposed SIP submission disapproval.[109] The EPA disagrees with Illinois's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2.[110] The state did not conduct an adequate Step 3 analysis.[111] The State included an insufficient evaluation of additional emissions control opportunities in its SIP submission.[112] The EPA also found technical and legal flaws in Illinois' arguments related to ''on-the-way'' controls, participation in the Lake Michigan Air Directors Consortium (LADCO), and international contributions.[113] The EPA further addresses the topic of international contribution in Section V.C.2. Further, as explained in Section V.B.9., states may not rely on non-SIP measures to meet SIP requirements, and reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[114] The State included no permanent and enforceable controls in its SIP submission.[115] We provide further response to comments regarding Illinois's SIP submission in the RTC document. The EPA is finalizing disapproval of Illinois's interstate

[90] *See also* id. at 64425–64426.

[91] *See also* id. at 64426.

[92] Id.

[93] 87 FR 9798, 9803–9806 (February 22, 2022).

[94] Id. at 9806–9807.

[95] Id. at 9808–9809.

[96] Id. at 9809–9810.

[97] Id. at 9809–9810.

[98] Id. at 9810.

[99] Id.

[100] Id. at 9811.

[101] We note that, consistent with the EPA's prior good neighbor actions in California, the regulatory ozone monitor located on the Morongo Band of Mission Indians (''Morongo'') reservation is a projected downwind receptor in 2023. *See* monitoring site 060651016 in Table V.D–1. of this action. We also note that the Temecula, California, regulatory ozone monitor is a projected downwind receptor in 2023 and in past regulatory actions has been deemed representative of air quality on the Pechanga Band of Luiseño Indians (''Pechanga'') reservation. *See, e.g.,* Approval of Tribal Implementation Plan and Designation of Air Quality Planning Area; Pechanga Band of Luiseño Mission Indians, 80 FR 18120, at 18121–18123 (April 3, 2015); *see* also monitoring site 060650016 in Table V.D–1. of this action. The presence of receptors on, or representative of, the Morongo and Pechanga reservations does not trigger obligations for the Morongo and Pechanga Tribes. Nevertheless, these receptors are relevant to the EPA's assessment of any linked upwind states' good neighbor obligations. *See, e.g.,* Approval and Promulgation of Air Quality State Implementation Plans; California; Interstate Transport Requirements for Ozone, Fine Particulate Matter, and Sulfur Dioxide, 83 FR 65093 (December 19, 2018). Under 40 CFR 49.4(a), tribes are not subject to the specific plan submittal and implementation deadlines for NAAQS-related requirements, including deadlines for submittal of plans addressing transport impacts. We also note that California's maximum contribution to a downwind state receptor is 6.31 ppb in Yuma County, Arizona (AQS Site ID 040278011).

[102] 87 FR 31448–31452.

[103] Id. at 31454–31457, 31460.

[104] Id. at 31458–31461.

[105] Id. at 31458.

[106] Id. at 31458–31459.

[107] Id. at 31461.

[108] *See also* id. at 31453.

[109] Id. at 9845.

[110] Id. at 9852–9853.

[111] Id. at 9853–9855.

[112] Id. at 9853.

[113] Id. at 9853–9854.

[114] *See also* id. at 9854.

[115] Id. at 9855.

transport SIP submission for the 2015 ozone NAAQS.

E. Indiana

In the 2016v3 modeling, Indiana is projected to be linked above 1 percent of the NAAQS to four nonattainment receptors and six maintenance-only receptors. It is also linked to 10 violating-monitor maintenance receptors. Its highest-level contribution is 10.03 ppb to Racine County, Wisconsin (AQS Site ID 551010020). A full summary of Indiana's November 2, 2018, SIP submission was provided in the proposed SIP submission disapproval.[116] The EPA disagrees with Indiana's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2.[117] The State did not conduct an adequate Step 3 analysis.[118] The EPA found technical and legal flaws in Indiana's arguments related to ozone concentration and design value trends, the timing of expected source shutdowns, local emissions, international and offshore contributions, Indiana's portion of contribution, and Indiana's back trajectory analysis.[119] The EPA further addresses the topic of international emissions in Section V.C.2. Indiana argued that it would not be cost-effective to implement controls on non-EGUs. However, the State included an insufficient evaluation of additional emissions control opportunities, for any type of source, to support that conclusion.[120] The EPA also confirmed that EGU shutdowns identified by Indiana were included in the 2016v2 modeling,[121] and if they were valid and not included in the 2016v2 modeling, then they were incorporated into the 2016v3 modeling as explained in Section III and the 2016v3 Emissions Modeling TSD. Further, in Section V.B.9., states may not rely on non-SIP measures to meet SIP requirements.[122] The State included no permanent and enforceable emissions controls in its SIP submission.[123] We provide further response to comments regarding Indiana's SIP submission in the RTC document. The EPA is finalizing disapproval of Indiana's interstate transport SIP submission for the 2015 ozone NAAQS.

[116] Id. at 9845–9847.

[117] Id. at 9855–9856.

[118] Id. at 9857–9861.

[119] Id. at 9858–9861.

[120] Id. at 9857–9858.

[121] Id. at 9858–9859.

[122] *See also* id. at 9861.

[123] Id.

F. Kentucky

In the 2016v3 modeling, Kentucky is projected to be linked above 1 percent of the NAAQS to two nonattainment receptors and one maintenance-only receptor. It is also linked to four violating-monitor maintenance-only receptor. Its highest-level contribution based on the 2016v3 modeling is 0.84 ppb to Fairfield County, Connecticut (AQS Site ID 090019003). A full summary of Kentucky's January 11, 2019, SIP submission was provided in the proposed SIP submission disapproval.[124] Although the EPA's 2016v3 modeling indicated a highest-level contribution below 1 ppb, the EPA disagrees with Kentucky's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2.[125] Further, Kentucky is linked above 1 ppb to a violating-monitor receptor. The EPA addresses the relevance of the PSD SILs in Section V.B.6. The Commonwealth did not conduct an adequate Step 3 analysis.[126] The EPA found technical and legal flaws in Kentucky's arguments related to the level and timing of upwind versus downwind-state responsibilities, NO_X emissions trends and other air quality information, and back-trajectory analyses.[127] The EPA also found technical and legal flaws in certain State-level comments submitted by Midwest Ozone Group and attached to Kentucky's submission, including arguments related to international emissions.[128] The EPA further addresses the topics of international emissions in Section V.C.2. Kentucky in its SIP submission also argued that it had already implemented all cost-effective controls. However, the Commonwealth included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[129] As explained in Section V.B.9., states may not rely on non-SIP measures to meet SIP requirements, and reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[130] The EPA also confirmed in the proposed SIP submission disapproval that EGU shutdowns identified by Kentucky were included in the 2016v2 modeling, and yet Kentucky was still linked in that modeling.[131] Kentucky in its SIP submission advocated for lower interstate ozone transport responsibility for states linked only to maintenance-only receptors. The EPA finds Kentucky's arguments in this regard inadequately supported.[132] The Commonwealth included no permanent and enforceable emissions controls in its SIP submission.[133] We provide further response to comments regarding Kentucky's SIP submission in the RTC document. The EPA is finalizing disapproval of Kentucky's interstate transport SIP submission for the 2015 ozone NAAQS.

[124] 87 FR 9498, 9503–9507 (February 22, 2022).

[125] Id. at 9509–9510.

[126] Id. at 9511–9515.

[127] Id. at 9512–9514.

[128] Id. at 9508, 9515. The state also did not explain its own views regarding the relevance of these materials to its submission. Id.

[129] Id. at 9511–9512.

[130] See also id. at. 9512.

G. Louisiana

In the 2016v3 modeling, Louisiana is projected to be linked above 1 percent of the NAAQS to two nonattainment receptors and five maintenance-only receptors. It is also linked to 10 violating-monitor maintenance-only receptor. Its highest-level contribution is 9.51 ppb to Galveston County Texas (AQS Site ID 481671034). A full summary of Louisiana's November 13, 2019, SIP submission was provided in the proposed SIP submission disapproval.[134] The EPA disagrees with Louisiana's arguments for application of a higher contribution threshold than 1 percent of the NAAQS and disagrees with Louisiana's criticisms of a 1 percent of the NAAQS contribution threshold at Step 2.[135] The EPA further addresses technical comments on the 1 percent of the NAAQS contribution threshold in Section V.B.4. Louisiana did not conduct an adequate Step 3 analysis.[136] The State included an insufficient evaluation of additional emissions control opportunities in its SIP submission.[137] The EPA also found technical flaws in Louisiana's "consistent and persistent" claims, assessment of seasonal weather patterns, surface wind directions, and back trajectory analysis.[138] The State included no permanent and enforceable controls in its SIP submission.[139] We provide further response to comments regarding Louisiana's SIP submission in the RTC document. The EPA is finalizing disapproval of Louisiana's interstate transport SIP submission for the 2015 ozone NAAQS.

[131] Id. at 9511–9512.

[132] Id. at 9514–9515.

[133] Id. at 9515.

[134] Id. at 9811–9812.

[135] Id. at 9812, 9815–9816.

[136] Id. at 9814–9816.

[137] Id. at 9814. 9816.

[138] Id. at 9814–9816.

[139] Id. at 9816.

H. Maryland

In the 2016v3 modeling, Maryland is projected to be linked above 1 percent of the NAAQS to three nonattainment receptors and one maintenance-only receptor. It is also linked to three violating-monitor maintenance receptors. Its highest-level contribution is 1.28 ppb to New Haven County, Connecticut (AQS Site ID 090099002). A full summary of Maryland's October 16, 2019, SIP submission was provided in the proposed SIP submission disapproval.[140] The state did not conduct an adequate Step 3 analysis.[141] The State included an insufficient evaluation of additional emissions control opportunities in its SIP submission.[142] Further, as explained in Section V.B.9, states may not rely on non-SIP measures to meet SIP requirements, and reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[143] The EPA also confirmed in the proposed SIP submission disapproval that state emissions controls and regulations identified by Maryland were generally included in the 2016v2 modeling, and yet Maryland was still linked in that modeling.[144] The State included no permanent and enforceable controls in its SIP submission.[145] We provide further response to comments regarding Maryland's SIP submission in the RTC document. The EPA is finalizing disapproval of Maryland's interstate transport SIP submission for the 2015 ozone NAAQS.

I. Michigan

In the 2016v3 modeling, Michigan is projected to be linked above 1 percent of the NAAQS to four nonattainment receptors and six maintenance-only receptors. It is also linked to eight violating-monitor maintenance receptors. Its highest-level contribution is 1.59 to Sheboygan County, Wisconsin (AQS Site ID 551170006). A full summary of Michigan's March 5, 2019, SIP submission was provided in the proposed SIP submission disapproval.[146] The EPA disagrees with Michigan's arguments for application of a higher contribution threshold than 1 percent of the NAAQS as well as criticisms of a 1 percent of the NAAQS contribution threshold at Step 2.[147] The EPA further addresses technical comments on the 1 percent of the NAAQS contribution threshold in Section V.B.4 and addresses comments regarding the relevance of the PSD SILs in Section V.B.6. The State did not conduct an adequate Step 3 analysis.[148] Michigan argued in its SIP submission that additional controls would be premature and burdensome. However, the State included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[149] The EPA found technical and legal flaws in Michigan's arguments related to upwind-state obligations as to maintenance-only receptors, international emissions, relative contribution, apportionment, and upwind versus downwind-state responsibilities.[150] The EPA further addresses the topics of mobile sources and international emissions in Sections V.C.1 and V.C.2, respectively. The EPA also confirmed in the proposed SIP submission disapproval that the EGU retirements identified by Michigan as not included in the 2011-based EPA modeling, as well as various Federal rules, were included in the 2016v2 modeling, and yet Michigan was still linked in that modeling.[151] The State included no permanent and enforceable emissions controls in its SIP submission.[152] We provide further response to comments regarding Michigan's SIP submission in the RTC document. The EPA is finalizing disapproval of Michigan's interstate transport SIP submission for the 2015 ozone NAAQS.

J. Minnesota

In the 2016v3 modeling, Minnesota is projected to be linked above 1 percent of the NAAQS to one maintenance-only receptor. It is not linked to a violating-monitor maintenance-only receptor. Its highest-level contribution is 0.85 ppb to Cook County, Illinois (AQS Site ID 170310001). A full summary of Minnesota's October 1, 2018, SIP submission was provided in the proposed SIP submission disapproval.[153] Because Minnesota was not projected to be linked to any receptor in 2023 in the EPA's 2011-based modeling, comments argued that the EPA must approve the SIP submission and not rely on new modeling. The EPA responds to these comments in Section V.A.4. Although the EPA acknowledges that Minnesota's Step 3 analysis was insufficient in part because the State assumed it was not linked at Step 2, this is ultimately inadequate to support a conclusion that the State's sources do not interfere with maintenance of the 2015 ozone NAAQS in other states in light of more recent air quality analysis.[154] The State included no permanent and enforceable emissions controls in its SIP submission.[155] We provide further response to comments regarding Minnesota's SIP submission in the RTC document. Although EPA proposed to disapprove both prong 1 and prong 2 of Minnesota's SIP submission, the present record, including the results of the 2016v3 modeling, indicates that Minnesota is not linked to any nonattainment receptors.[156] The EPA is finalizing a partial approval of Minnesota's interstate transport SIP submission for the 2015 ozone NAAQS as to prong 1 and a partial disapproval as to prong 2.

K. Mississippi

In the 2016v3 modeling, Mississippi is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor and two maintenance-only receptors. It is also linked to eight violating-monitor maintenance receptors. Its highest-level contribution is 1.32 ppb to Galveston County, Texas (AQS Site ID 481671034). A full summary of Mississippi's September 3, 2019, SIP submission was provided in the proposed SIP submission disapproval.[157] In its submission, Mississippi advocated for discounting receptors through use of historical data trends. The EPA finds Mississippi's approach is not adequately justified.[158] In the 2011-based modeling, Mississippi's contribution to receptors was above 1 percent of the NAAQS, but below 1 ppb. The EPA disagrees with Mississippi's arguments for application of a higher contribution threshold than

[140] Id. at 9469.

[141] Id. at 9470–9473.

[142] Id. at 9471, 9473.

[143] *See also* id. at 9471, 9473 n.46, 9474.

[144] Id. at 9472–9473.

[145] Id. at 9473–9474.

[146] Id. at 9847–9848.

[147] Id. at 9861–9862.

[148] Id. at 9863–9867.

[149] Id. at 9864.

[150] Id. at 9864–9867.

[151] Id. at 9866.

[152] Id. at 9867.

[153] Id. at 9867.

[154] Id. at 9868–9869.

[155] Id. at 9869.

[156] The EPA received a comment that it would be arbitrary and capricious for the EPA to finalize a full disapproval of Tennessee's good neighbor SIP submission (both prong 1 and prong 2) if EPA concluded the state is linked only to a maintenance-only receptor (prong 2). EPA is deferring final action on Tennessee's good neighbor SIP submission, but in reviewing linkages in the 2016v3 modeling we determined that Minnesota and Wisconsin are not linked above 1 percent of the NAAQS to any nonattainment receptors (prong 1) but are linked to maintenance-only receptors (prong 2); these states are receiving partial approvals and partial disapprovals.

[157] 87 FR 9554.

[158] Id. at 9556.

1 percent of the NAAQS at Step 2,[159] and further addresses the relevance of the PSD SILs in Section V.B.6. The state did not conduct a Step 3 analysis.[160] The State included no evaluation of additional emissions control opportunities in its SIP submission.[161] The State included no permanent and enforceable emissions controls in its SIP submission.[162] We provide further response to comments regarding Mississippi's SIP submission in the RTC document. The EPA is finalizing disapproval of Mississippi's interstate transport SIP submission for the 2015 ozone NAAQS.

L. Missouri

In the 2016v3 modeling, Missouri is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor and three maintenance-only receptors. It is also linked to five violating-monitor maintenance receptors. Its highest-level contribution is 1.87 ppb to Sheboygan County, Wisconsin (AQS Site ID 551170006). A full summary of Missouri's June 10, 2019, SIP submission was provided in the proposed SIP submission disapproval.[163] In its submission, Missouri advocated for discounting certain maintenance receptors through use of historical data trends. The EPA finds Missouri's approach is not adequately justified.[164] The EPA disagrees with Missouri's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2, and further addresses comments regarding the August 2018 memorandum in Section V.B.7.[165] The State did not conduct a Step 3 analysis.[166] The State included no evaluation of additional emissions control opportunities in its SIP submission.[167] The State included no permanent and enforceable emissions controls in its SIP submission.[168] We provide further response to comments regarding Missouri's SIP submission in the RTC document. The EPA is finalizing disapproval of Missouri's June 10, 2019, interstate transport SIP submission for the 2015 ozone NAAQS.

M. Nevada

In the 2016v3 modeling, Nevada is projected to be linked above 1 percent of the NAAQS to three nonattainment receptors and one maintenance-only receptor. It is also linked to one violating-monitor maintenance receptor. Its highest-level contribution is 1.13 ppb to Weber County, Utah (AQS Site ID 490570002). A full summary of Nevada's October 1, 2018, SIP submission was provided in the proposed SIP submission disapproval.[169] Because Nevada was not projected to be linked to any receptor in 2023 in the EPA's 2011-based modeling, commenters on the proposed SIP submission disapproval argued that the EPA must approve the SIP submission and not rely on new modeling. The EPA responds to these comments in Section V.A.4. The EPA also responds to technical criticisms of the 1 percent of the NAAQS contribution threshold and the relevance of the PSD SILs in Section V.B.4 and in Section V.B.6, respectively. The State did not conduct a Step 3 analysis.[170] The State included no evaluation of additional emissions control opportunities in its SIP submission.[171] The State included no additional emissions controls in its SIP submission.[172] We provide response to comments specific to interstate transport policy in the western U.S. in Section V.C.3. We provide further response to comments regarding Nevada's SIP submission in the RTC document. The EPA is finalizing disapproval of Nevada's interstate transport SIP submission for the 2015 ozone NAAQS.

N. New Jersey

In the 2016v3 modeling, New Jersey is projected to be linked above 1 percent of the NAAQS to three nonattainment receptors and one maintenance-only receptor. It is also linked to three violating-monitor maintenance receptors. Its highest-level contribution is 8.38 ppb to Fairfield County, Connecticut (AQS Site ID 090019003). A full summary of New Jersey's May 13, 2019, SIP submission was provided in the proposed SIP submission disapproval.[173] The State did not conduct an adequate Step 3 analysis.[174] New Jersey argued in its SIP submission that existing controls were sufficient to address the State's good neighbor obligations. However, the State included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[175] The State's reliance on the cost-effectiveness threshold in the CSAPR Update is insufficient for a more protective NAAQS.[176] The State included no permanent and enforceable emissions controls in its SIP submission.[177] We provide further response to comments regarding New Jersey's SIP submission in the RTC document. The EPA is finalizing disapproval of New Jersey's interstate transport SIP submission for the 2015 ozone NAAQS.

O. New York

In the 2016v3 modeling, New York is projected to be linked above 1 percent of the NAAQS to three nonattainment receptors and one maintenance-only receptor. It is also linked to two violating-monitor maintenance receptors. Its highest-level contribution is 16.10 ppb to Fairfield County, Connecticut (AQS Site ID 090010017). A full summary of New York's September 25, 2018, SIP submission was provided in the proposed SIP submission disapproval.[178] The state did not conduct an adequate Step 3 analysis.[179] New York argued in its SIP submission that existing controls were sufficient to address the State's good neighbor obligations. However, the state included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[180] The State's reliance on the cost-effectiveness threshold in the CSAPR Update is insufficient for the more protective 2015 ozone NAAQS.[181] The State included no permanent and enforceable emissions controls in its SIP submission.[182] We provide further response to comments regarding New York's SIP submission in the RTC document. The EPA is finalizing disapproval of New York's interstate transport SIP submission for the 2015 ozone NAAQS.

P. Ohio

In the 2016v3 modeling, Ohio is projected to be linked above 1 percent of the NAAQS to four nonattainment receptors and five maintenance-only

[159] Id. at 9557.
[160] Id. at 9558.
[161] Id.
[162] Id.
[163] Id. at 9538–9540.
[164] Id. at 9540–9541.
[165] *See also* id. at 9541–9544.
[166] Id. at 9544.
[167] Id.
[168] We note that in comments, Missouri indicated its intent to submit a new SIP submission to the EPA, which would re-evaluate good neighbor obligations based on its 2016v2 linkages and provide an analysis that would include emissions reductions requirements. The EPA received this submission on November 1, 2022. The EPA explains its consideration of this new submission as separate SIP submission in the RTC document for this final action.
[169] 87 FR 31485, 31492–31493 (May 24, 2022).
[170] Id. at 31493.
[171] Id.
[172] Id.
[173] Id. at 9490–9491.
[174] Id. at 9496.
[175] Id.
[176] Id.
[177] Id. at 9496–9497.
[178] Id. at 9489–9490.
[179] Id. at 9492–9494.
[180] Id. at 9493.
[181] Id. at 9493–9494.
[182] Id. at 9494–9495.

receptors. It is also linked to nine violating-monitor maintenance receptors. Its highest-level contribution is 2.05 ppb to Fairfield County, Connecticut (AQS Site ID 090019003). A full summary of Ohio's September 28, 2018, SIP submission was provided in the proposed SIP submission disapproval.[183] In its submission, Ohio advocated for use of the Texas Commission on Environmental Quality (TCEQ)'s definition of maintenance receptors. The EPA finds that TCEQ's definition is legally and technically flawed,[184] and as a result Ohio's approach is also not adequately justified.[185] The EPA further evaluates TCEQ's technical arguments in a TSD prepared by regional modeling staff.[186] The EPA disagrees with Ohio's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2.[187] The EPA responds to technical criticisms of the 1 percent of the NAAQS contribution threshold in Section V.B.4. The State did not conduct an adequate Step 3 analysis.[188] The State included an insufficient evaluation of additional emissions control opportunities in its SIP submission.[189] The EPA found technical deficiencies in Ohio's unsubstantiated claims that emissions are overestimated.[190] The EPA also confirmed in the proposed SIP submission disapproval that several EGU and non-EGUs identified by Ohio were included in the 2016v2 modeling, and yet Ohio was still linked in that modeling.[191] The EPA summarizes the emissions inventories used in the 2016v3 modeling in Section III.A. Further, as explained in Section V.B.9, states may not rely on non-SIP measures to meet SIP requirements, and reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[192] The EPA finds legal flaws and deficiencies in Ohio's arguments related to upwind versus downwind-state responsibilities, the role of international emissions, relative contribution, and overcontrol.[193] The EPA discusses international emissions in Section V.C.2. The EPA disagrees with Ohio's arguments related to mobile sources.[194] We further address this topic in Section V.C.1. Ohio also argued in its SIP submission that it had already implemented all cost-effective controls. However, the state included no evaluation of additional emissions control opportunities to support such a claim.[195] Further, the State's reliance on the cost-effectiveness threshold in the CSAPR Update is insufficient for the more protective 2015 ozone NAAQS.[196] The State included no permanent and enforceable emissions controls in its SIP submission.[197] We provide further response to comments regarding Ohio's SIP submission in the RTC document. The EPA is finalizing disapproval of Ohio's interstate transport SIP submission for the 2015 ozone NAAQS.

Q. Oklahoma

In the 2016v3 modeling, Oklahoma is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor and one maintenance-only receptor. It is also linked to eight violating-monitor maintenance receptors. Its highest-level contribution is 1.01 ppb to Denton County, Texas (AQS Site ID 481210034). A full summary of Oklahoma's October 25, 2018, SIP submission was provided in the proposed SIP submission disapproval.[198] In its submission, Oklahoma advocated for use of TCEQ's definition of maintenance receptors and modeling to discount receptors in Texas. The EPA finds that TCEQ's definition is legally and technically flawed [199] and, as a result, Oklahoma's approach is also not adequately justified.[200] The EPA further evaluates TCEQ's technical arguments in the EPA Region 6 2015 8-Hour Ozone Transport SIP Proposal TSD (Evaluation of TCEQ Modeling TSD) prepared by regional modeling staff.[201] Comments argued against the use of updated modeling where linkages in the EPA's 2011-based modeling and later iterations of EPA modeling differ. The EPA addressed the change in identified linkages between the 2011-based modeling and the 2016v2 modeling in the proposed SIP disapproval,[202] and further responds to comments on the use of updated modeling in Section V.A.4. The EPA disagrees with Oklahoma's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2 [203] and further addresses comments regarding the relevance of the PSD SILs in Section V.B.6. The State did not conduct an adequate Step 3 analysis.[204] Oklahoma argued in its SIP submission that it had already implemented all cost-effective controls. However, the State included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[205] As explained in Section V.B.9, states may not rely on non-SIP measures to meet SIP requirements, and reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[206] Further, the State's reliance on the cost-effectiveness threshold in the CSAPR Update is insufficient for the more protective 2015 ozone NAAQS.[207] The EPA finds legal flaws in Oklahoma's argument related to collective contribution.[208] The State included no permanent and enforceable emissions controls in its SIP submission.[209] We provide further response to comments regarding Oklahoma's SIP submission in the RTC document. The EPA is finalizing disapproval of Oklahoma's interstate transport SIP submission for the 2015 ozone NAAQS.

R. Texas

In the 2016v3 modeling, Texas is projected to be linked above 1 percent of the NAAQS to one nonattainment receptor and nine maintenance-only receptors. It is also linked to ten violating-monitor maintenance-only receptor. Its highest-level contribution is 4.74 ppb to Dona Ana County, New Mexico (AQS Site ID 350130021). A full summary of Texas's August 17, 2018, SIP submission was provided in the proposed SIP submission disapproval,[210] and additional details were provided in the Evaluation of TCEQ Modeling TSD. The EPA identified several technical flaws in TCEQ's modeling and analysis of modeling results.[211] In its submission, Texas advocated for use of its own definition of maintenance receptors and modeling. The EPA finds Texas's approach inadequately justified and

[183] Id. at 9849–9851.

[184] Id. at 9826–9829.

[185] Id. at 9869–9870.

[186] 2015 8-Hour Ozone Transport SIP Proposal TSD, in Docket ID No. EPA–R06–OAR–2021–0801 (hereinafter Evaluation of TCEQ Modeling TSD).

[187] Id. at 9871.

[188] Id. at 9871–9875.

[189] Id. at 9871–9875.

[190] Id. at 9872.

[191] Id.

[192] *See also* id. at 9874–9875.

[193] Id. at 9873–9874.

[194] Id.

[195] Id. at 9872–9873.

[196] Id. at 9874.

[197] Id. at 9875.

[198] Id. at 9816–9818.

[199] Id. at 9826–9829.

[200] Id. at 9820–9822.

[201] Evaluation of TCEQ Modeling TSD in Docket ID No. EPA–R06–OAR–2021–0801.

[202] 87 FR 9823.

[203] Id. at 9819.

[204] Id. at 9822–9824.

[205] Id. at 9822–9824.

[206] *See also* id. at. 9822–9823.

[207] Id.

[208] Id. at 9823.

[209] Id. at 9824.

[210] Id. at 9824–9826.

[211] Id. at 9829–9830; Evaluation of TCEQ Modeling TSD.

legally and technically flawed.[212] The EPA further evaluated TCEQ's technical arguments in the Evaluation of TCEQ Modeling TSD. In comment on the proposal, Texas pointed to differences in linkages in the EPA's 2011-based modeling and 2016v2 modeling. The EPA addressed the change in identified linkages between the 2011-based modeling and the 2016v2 modeling in the proposed SIP submission disapproval,[213] and further responds to comments on the use of updated modeling in Section V.A.4. The State did not conduct an adequate Step 3 analysis.[214] The State included an insufficient evaluation of additional emissions control opportunities in its SIP submission.[215] The EPA found technical flaws in Texas's arguments related to ''consistent and persistent'' claims and its other assessments, including analysis of back trajectories.[216] The State included no permanent and enforceable emissions controls in its SIP submission.[217] We provide further response to comments regarding Texas's SIP submission in the RTC document. The EPA is finalizing disapproval of Texas's interstate transport SIP submission for the 2015 ozone NAAQS.

S. Utah

In the 2016v3 modeling, Utah is projected to be linked above 1 percent of the NAAQS to three nonattainment receptors and one maintenance-only receptor. It is also linked to four violating-monitor maintenance receptors. Its highest-level contribution is 1.29 ppb to Douglas County, Colorado (AQS Site ID 080350004). A full summary of Utah's January 29, 2020, SIP submission was provided in the proposed SIP submission disapproval.[218] In its submission, Utah argued that certain receptors in Colorado should not be counted as receptors for the purpose of 2015 ozone NAAQS interstate transport, but Utah's explanation is insufficient to discount those receptors.[219] The EPA disagrees with Utah's arguments for application of a higher contribution threshold than 1 percent of the NAAQS at Step 2.[220] Utah suggested in its SIP submission that interstate transport is fundamentally different in the western U.S. than in the eastern U.S., an argument we have previously rejected and respond to further in Section V.C.3.[221] The State did not conduct an adequate Step 3 analysis.[222] The State included an insufficient evaluation of additional emissions control opportunities in its SIP submission.[223] The EPA finds technical and legal flaws in the State's arguments related to relative contribution, international and non-anthropogenic emissions, and the relationship of upwind versus downwind-state responsibilities.[224] The EPA further addresses the topics of international emissions in Section V.C.2 and wildfires in the RTC document. The EPA also confirmed in the proposed SIP submission disapproval that several anticipated controls identified by Utah were included in the 2016v2 modeling, and yet Utah was still linked in that modeling.[225] The State included no permanent and enforceable emissions controls in its SIP submission.[226] We provide further response to comments regarding Utah's SIP submission in the RTC document. The EPA is finalizing disapproval of Utah's interstate transport SIP submission for the 2015 ozone NAAQS.

T. West Virginia

In the 2016v3 modeling, West Virginia is projected to be linked above 1 percent of the NAAQS to three nonattainment receptors and one maintenance-only receptor. It is also linked to four violating-monitor maintenance receptors. Its highest-level contribution is 1.49 ppb to New Haven County, Connecticut (AQS Site ID 090099002). A full summary of West Virginia's February 4, 2019, SIP submission was provided in the proposed SIP submission disapproval.[227] The EPA finds technical and legal flaws in the State's examination of back trajectories and arguments related to mobile sources and international emissions.[228] The EPA further addresses the topics of mobile sources and international emissions in Section V.C.1 and in Section V.C.2, respectively. The State did not conduct an adequate Step 3 analysis.[229] West Virginia argued in its SIP submission that it had already implemented all cost-effective controls. However, the State included an insufficient evaluation of additional emissions control opportunities to support such a conclusion.[230] The EPA also confirmed in the proposed SIP submission disapproval that specific EGU shutdowns identified by West Virginia were included in the 2016v2 modeling, which continued to show West Virginia was linked at Step 2.[231] As explained in Section V.B.9, a state may not rely on non-SIP measures to satisfy SIP requirements, and reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[232] Further, the State's reliance on the cost-effectiveness threshold in the CSAPR Update is insufficient for a more protective NAAQS.[233] The State included no permanent and enforceable emissions controls in its SIP submission.[234] We provide further response to comments regarding West Virginia's SIP submission in the RTC document. The EPA is finalizing disapproval of West Virginia's interstate transport SIP submission for the 2015 ozone NAAQS.

U. Wisconsin

In the 2016v3 modeling, Wisconsin is projected to be linked above 1 percent of the NAAQS to three maintenance-only receptors. It is also linked to five violating-monitor maintenance receptors. Its highest-level contribution is 2.86 ppb to Cook County, Illinois (AQS Site ID 170314201). A full summary of Wisconsin's September 14, 2018, SIP submission was provided in the proposed SIP submission disapproval.[235] The State did not assess in its SIP submission whether the state was linked at Step 2,[236] and did not conduct an adequate Step 3 analysis.[237] The State included an insufficient evaluation of additional emissions control opportunities.[238] Further, as explained in Section V.B.9, reliance on prior transport FIPs such as the CSAPR Update is not a sufficient analysis at Step 3.[239] The EPA found additional inadequacies and legal flaws in Wisconsin's submission.[240] The State included no permanent and enforceable emissions controls in its SIP submission.[241] We provide further response to comments regarding

[212] 87 FR 9826–9829.
[213] Id. at 9831.
[214] Id. at 9831–9834.
[215] Id. at 9831, 9834.
[216] Id. at 9832–9833, Evaluation of TCEQ Modeling TSD.
[217] 87 FR 9834.
[218] Id. at 31475–31477.
[219] Id. at 31480–31481.
[220] Id. at 31478.
[221] *See also* id. at 31479–31481, 31482.
[222] Id. at 31481–31483.
[223] Id. at 31482
[224] Id. at 31481–31483.
[225] Id. at 31483.
[226] Id.
[227] Id. at 9522–9524.
[228] Id. at 9526–9527, 9528.
[229] Id. at 9527–9532.
[230] Id. at 9528–9529.
[231] Id. at 9529–9530.
[232] *See also* id. at 9530–9532.
[233] Id. at 9531.
[234] Id. at 9532.
[235] Id. at 9851.
[236] Id. at 9875.
[237] Id. at 9875–9876.
[238] Id. at 9876.
[239] *See also* id.
[240] Id.
[241] Id. at 9876–9877.

Wisconsin's SIP submission in the RTC document. Although EPA proposed to disapprove both prong 1 and prong 2 of Wisconsin's SIP submission, the present record, including the results of the 2016v3 modeling, indicates that Wisconsin is not linked to any nonattainment receptors.[242] The EPA is finalizing a partial approval of Wisconsin's interstate transport SIP submission for the 2015 ozone NAAQS as to prong 1 and a partial disapproval as to prong 2.

V. Response to Key Comments

The EPA received numerous comments on the proposed action which are summarized in the RTC document along with the EPA's responses to those comments in Docket ID No. EPA–HQ–OAR–2021–0663. Each comment in its entirety is available in the relevant regional docket(s) for this action.[243] The following sections summarize key comments and the EPA's responses.

A. SIP Evaluation Process

1. Relationship Between Timing of Proposals To Disapprove SIPs and Promulgate FIPs

Comment: Comments alleged generally that the timing of the EPA's proposed actions on the SIP submissions in relation to proposed FIPs was unlawful, unfair, or both. Some comments claimed that the sequence of the EPA's actions is improper, unreasonable, or bad policy. Several commenters asserted that because the EPA proposed FIPs (or, according to some, promulgated FIPs, which is not factually correct) prior to finalizing disapproval of the state SIP submission, the EPA allegedly exceeded its statutory authority and overstepped the states' primary role in addressing the good neighbor provision under CAA section 110.[244]

EPA Response: The EPA disagrees. The EPA has followed the Clean Air Act provisions, which prescribe specified maximum amounts of time for states to make SIP submissions, for the EPA to act on those submissions, and for the EPA to promulgate FIPs if necessary, but do not prohibit the EPA from acting before that time elapses. Nothing relieves the EPA from its statutory obligation to take final action on complete SIP submissions before the Agency within the timeframes prescribed by the statute.[245] The EPA's proposed FIP does not constitute the ''promulgation'' of a FIP because the proposed FIP is not a final action that imposes any requirements on sources or states. And although the EPA's FIP authority is not at issue in this action, the EPA notes the Agency has been clear that it will not finalize a FIP for any state until predicate authority is established for doing so under CAA section 110(c)(1). 87 FR 20036, 20057 (April 6, 2022) (''The EPA is proposing this FIP action now to address twenty-six states' good neighbor obligations for the 2015 ozone NAAQS, but the EPA will not finalize this FIP action for any state unless and until it has issued a final finding of failure to submit or a final disapproval of that state's SIP submission.''). The EPA strongly disagrees that *proposing* a FIP prior to proposing or finalizing disapproval of a SIP submission oversteps the Agency's authority. Indeed, the ability to propose a FIP before finalizing a SIP disapproval follows ineluctably from the structure of the statute, which, as the Supreme Court recognized in *EME Homer City,* does not oblige the EPA ''to wait two years or postpone its [FIP] action even a single day.'' 572 U.S. at 509. If the EPA can finalize a FIP immediately upon disapproving a SIP, then surely the EPA must have the authority to propose that FIP before taking final action on the SIP submission. *Accord Oklahoma* v. *U.S. EPA,* 723 F.3d 1201, 1223 (10th Cir. 2013).

It is true that the EPA would not be legally authorized to *finalize* a FIP for any state unless and until the EPA formally *finalizes* a disapproval of that state's SIP submission (or makes a finding of failure to submit for any state that fails to make a complete SIP submission), per CAA section 110(c), but the EPA has not yet finalized a FIP for any state for good neighbor obligations for the 2015 ozone NAAQS. Further, the sequencing of our actions here is consistent with the EPA's past practice in our efforts to timely address good neighbor obligations. For example, at the time the EPA proposed the CSAPR Update FIPs in December of 2015, we had not yet proposed action on several states' SIP submissions but finalized those SIP disapproval actions prior to finalization of the FIP.[246]

Additional comments on cooperative federalism are addressed in Section V.B.5.

Further, The D.C. Circuit in *Wisconsin* held that states and the EPA are obligated to fully address good neighbor obligations for ozone ''as expeditiously as practical'' and in no event later than the next relevant downwind attainment dates found in CAA section 181(a),[247] and states and the EPA may not delay implementation of measures necessary to address good neighbor requirements beyond the next applicable attainment date without a showing of impossibility or necessity.[248] It is important for the states and the EPA to assure that necessary emissions reductions are achieved, to the extent feasible, by the 2023 ozone season to assist downwind areas with meeting the August 3, 2024, attainment deadline for Moderate nonattainment areas. Further, the D.C. Circuit in *Wisconsin* emphasized that the EPA has the authority under CAA section 110 to structure its actions so as to ensure necessary reductions are achieved by the downwind attainment

[242] The EPA received a comment that it would be arbitrary and capricious for the EPA to finalize a full disapproval of Tennessee's good neighbor SIP submission (both prong 1 and prong 2) if EPA concluded the State is linked only to a maintenance-only receptor (prong 2).The EPA is deferring final action on Tennessee's good neighbor SIP submission, but in reviewing linkages in the 2016v3 modeling we determined that Minnesota and Wisconsin are not linked above 1 percent of the NAAQS to any nonattainment receptors (prong 1) but are linked to maintenance-only receptors (prong 2); these States are receiving partial approvals and partial disapprovals.

[243] *See* the memo ''Regional Dockets Containing Additional Supporting Materials for Final Action on 2015 Ozone NAAQS Good Neighbor SIP Submissions'' in the docket for this action, for a list of all regional dockets.

[244] The EPA notes the commenters' reference to FIPs is to proposed good neighbor FIPs for the 2015 ozone NAAQS that were proposed separately from this rulemaking action. 87 FR 20036 (April 6, 2022).

[245] Although the EPA anticipates responding to comments related to the EPA's FIP authority in a separate FIP rulemaking, the EPA notes with regard to the procedural timing concerns raised in comments on this action that the Supreme Court confirmed in *EME Homer City Generation,* ''EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP 'at any time' within the two-year limit.'' 572 U.S. 489 at 509. The procedural timeframes under CAA section 110 do not function to establish a norm or expectation that the EPA must or should use the full amount of time allotted, particularly when doing so would place the Agency in conflict with the more ''central'' statutory objective of meeting the NAAQS attainment deadlines in the Act. *EME Homer City,* 572 U.S. 489, 509 (2014). *See also Wisconsin,* 938 F.3d at 318, 322; *Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002) (*Sierra Club*).

[246] The proposed CSAPR Update was published on December 3, 2015, and included proposed FIPs for Indiana, Louisiana, New York, Ohio, Texas, and Wisconsin. 80 FR 75705. At that time, the EPA had not yet even proposed action on good neighbor SIP submissions for the 2008 ozone NAAQS from Indiana, Louisiana, New York, Ohio, Texas, and Wisconsin; however, the EPA subsequently proposed and finalized these disapprovals before finalizing the CSAPR Update FIPs, published on October 26, 2016 (81 FR 74504). *See* 81 FR 38957 (June 15, 2016) (Indiana); 81 FR 53308 (August 12, 2016) (Louisiana); 81 FR 58849 (August 26, 2016) (New York); 81 FR 38957 (June 15, 2016) (Ohio); 81 FR 53284 (August 12, 2016) (Texas); 81 FR 53309 (August 12, 2016) (Wisconsin).

[247] *Wisconsin,* 938 F.3d at 313–14 (citing *North Carolina,* 531 F.3d at 911–12.

[248] *See Wisconsin,* 938 F.3d at 320.

dates,[249] the next of which for the 2015 ozone NAAQS is now the Moderate area attainment date of August 3, 2024.[250] The court pointed out that the CAA section 110 schedule of SIP and FIP deadlines is procedural whereas the attainment schedule is ''central to the regulatory scheme[.]'' [251] Thus, the sequence and timing of the EPA's action in disapproving these SIP submissions is informed by the need to ensure that any necessary good neighbor obligations identified in the separate FIP rulemaking are implemented as expeditiously as practicable and no later than the next attainment date. As explained in our proposed disapproval, analysis (and, if possible, implementation) of good neighbor obligations should begin in the 2023 ozone season. *See, e.g.,* 87 FR 9798, 9801–02 (Feb. 22, 2022). Indeed, states' and the EPA's analysis would have been more appropriately aligned with 2020, rather than 2023 (as had been presented in the EPA's March 2018 memorandum [252]), corresponding with the 2021 Marginal area attainment date. However, that clarification in legal obligations was not established by case law until 2020. *See Maryland,* 958 F.3d at 1203–04.

In short, nothing in the language of CAA section 110(c) prohibits the EPA from proposing a FIP as a backstop, to be finalized and implemented only in the event that a SIP submission is first found to be deficient and final disapproval action on the SIP submission is taken. Such an approach is a reasonable and prudent means of assuring that the statutory obligation to reduce air pollution affecting the health and welfare of those living in downwind states is implemented without delay, either via a SIP, or where such plan is deficient, via a FIP. The sequencing of the EPA's actions here is therefore reasonably informed by its legal obligations under the CAA, including in recognition of the fact that the implementation of necessary emissions reductions to eliminate significant contribution and thereby protect human health and welfare is already several years delayed. The EPA shares additional responses related to the timing of 2015 ozone NAAQS good neighbor actions in Section V.A.

Comment: Some comments allege the EPA is depriving States of the opportunity to target specific emissions reductions opportunities, or the opportunity to revise their submissions at any point in the future.

EPA Response: The EPA disagrees. The EPA has repeatedly emphasized that states have the freedom at any time to develop a revised SIP submission and submit that to the EPA for approval, and this remains true. *See* 87 FR 20036, 20051 (April 6, 2022); 86 FR 23054, 23062 (April 30, 2021); 81 FR 74504, 74506 (Oct. 26, 2016). In the proposed FIPs, as in prior transport actions, the EPA discusses a number of ways in which states could take over or replace a FIP, *see* 87 FR 20036, 20149–51 (Section VII.D: ''Submitting A SIP''); *see also id.* at 20040 (noting as one purpose in proposing the FIP that ''this proposal will provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes necessary to eliminate significant contribution''). If, and when, the EPA receives a SIP submission that satisfies the requirements of CAA section 110(a)(2)(D)(i)(I), the Agency will take action to approve that SIP submission.

Comment: Some commenters assert that the EPA is disapproving SIP submissions for the sole purpose of pursuing an alleged objective of establishing nation-wide standards in FIPs. Other commenters point to the proposed FIPs to make arguments that the EPA's decision to finalize disapproval of the SIPs is an allegedly foregone conclusion or that the EPA has allegedly failed to provide the opportunity for meaningful public engagement on the proposed disapproval of the SIPs.

EPA Response: The EPA disagrees as the facts do not support this assertion. To date, the EPA has approved 24 good neighbor SIPs for the 2015 ozone NAAQS: Alaska,[253] Colorado,[254] Connecticut,[255] Delaware,[256] District of Columbia,[257] Florida,[258] Georgia,[259] Hawaii,[260] Idaho,[261] Iowa,[262] Kansas,[263] Maine,[264] Massachusetts,[265] Montana,[266] Nebraska,[267] New Hampshire,[268] North Carolina,[269] North Dakota,[270] Oregon,[271] Rhode Island,[272] South Carolina,[273] South Dakota,[274] Vermont,[275] and Washington.[276]

The policy judgments made by the EPA in all actions on 2015 ozone NAAQS good neighbor SIP submissions, including approval actions, reflect consistency with relevant good neighbor case law and past agency practice implementing the good neighbor provision as reflected in the original CSAPR, CSAPR Update, Revised CSAPR Update, and related rulemakings. Employing a nationally consistent approach is particularly important in the context of interstate ozone transport, which is a regional-scale pollution problem involving many smaller contributors. Effective policy solutions to the problem of interstate ozone transport dating back to the NO_X SIP Call [63 FR 57356 (October 27, 1998)] have necessitated the application of a uniform framework of policy judgments to ensure an ''efficient and equitable'' approach. *See EME Homer City,* 572 U.S. at 519. In any case, the approach of the proposed transport FIP is not the subject of this SIP disapproval. This rulemaking does not impose any specific emissions control measures on the states. Nor is the EPA disapproving these SIP submittals because they did not follow exactly the control strategies in the proposed FIP—the EPA has repeatedly indicated openness to alternative approaches to addressing interstate pollution obligations, but for reasons explained elsewhere in the rulemaking record, the EPA finds that none of the states included in this action submitted approvable approaches to addressing those obligations.

The EPA disputes the contentions that the FIP proposal itself indicates that the EPA did not earnestly examine the SIP submissions for compliance with the CAA or have an appropriate rationale

[249] *Wisconsin,* 938 F.3d at 318 (''When EPA determines a State's SIP is inadequate, the EPA presumably must issue a FIP that will bring that State into compliance before upcoming attainment deadlines, even if the outer limit of the statutory timeframe gives the EPA more time to formulate the FIP.'') (citing *Sierra Club,* 294 F.3d at 161).

[250] *See* CAA section 181(a); 40 CFR 51.1303; Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards, 83 FR 25776 (June 4, 2018, effective August 3, 2018).

[251] *Wisconsin,* 938 F.3d at 322 (''Delaware's argument leans too heavily on the SIP submission deadline. SIP submission deadlines, unlike attainment deadlines, are 'procedural' and, therefore, not 'central to the regulatory scheme.' '') (citing *Sierra Club,* 294 F.3d at 161).

[252] *See* March 2018 memorandum.

[253] 84 FR 69331 (December 18, 2019).

[254] 87 FR 61249 (October 11, 2022).

[255] 86 FR 71830 (December 20, 2021).

[256] 85 FR 25307 (May 1, 2020).

[257] 85 FR 5570 (January 31, 2020).

[258] 86 FR 68413 (December 2, 2021).

[259] Id.

[260] 86 FR 73129 (December 27, 2021).

[261] 85 FR 65722 (October 16, 2020).

[262] 87 FR 22463 (April 15, 2022).

[263] 87 FR 19390 (April 4, 2022).

[264] 86 FR 45870 (August 17, 2021).

[265] 85 FR 5572 (January 31, 2020).

[266] 87 FR 21578 (April 12, 2022).

[267] 85 FR 21325 (April 17, 2020).

[268] 86 FR 45870 (August 17, 2021).

[269] 86 FR 68413 (December 2, 2021).

[270] 85 FR 20165 (April 10, 2020).

[271] 84 FR 22376 (May 17, 2019).

[272] 86 FR 70409 (December 10, 2021).

[273] 86 FR 68413 (December 2, 2021).

[274] 85 FR 67653 (October 26, 2020).

[275] 85 FR 34357 (June 4, 2020).

[276] 83 FR 47568 (September 20, 2018).

for proposing to disapprove certain SIP submissions. The EPA also disputes that the FIP proposal indicates that the EPA did not intend to consider comments on the proposed disapprovals. Comments making claims the EPA did not follow proper administrative procedure have been submitted utilizing the very notice and comment process these comments claim the EPA is skipping, and these claims are factually unsupported. Comments related to the length of the comment period and claims of ''pretext'' are addressed in the RTC document.

Comment: Several comments pointed out how hard many states have worked to develop an approvable SIP submission.

EPA Response: The EPA acknowledges and appreciates states' efforts to develop approvable SIPs. Cooperative federalism is a cornerstone of CAA section 110, and the EPA strives to collaborate with its state partners. The timing of the EPA's 2015 ozone NAAQS good neighbor actions is not in any way intended to call into question any state's commitment to develop approvable SIPs. The EPA evaluated each SIP submission on its merits. The EPA relies on collaboration with state air agencies to ensure SIP submissions are technically and legally defensible, and the Agency's action here is in no way meant to undermine that collaboration between state and Federal partners respecting SIP development.

Comment: Several comments make various arguments about when the EPA can finalize FIPs. Some commenters argue that CAA section 110(c)(1) guarantees states an additional two years to correct their SIP submissions before the EPA finalizes a FIP. Others argue that the notice and comment requirements of the Administrative Procedures Act mandate that the EPA finalize a SIP submission disapproval before proposing a FIP. One commenter suggested that a state must be allowed to fully exhaust its judicial remedies to challenge a SIP submission disapproval before the EPA can promulgate a FIP. Commenters also raise concerns about the analysis and requirements in the proposed FIPs.

EPA Response: Comments opining on when the EPA is legally authorized to propose or finalize a FIP are outside the scope of this action. While the EPA acknowledges that the Agency has no obligation or authority to finalize a FIP until finalizing a disapproval of a SIP submission or determining that a state failed to submit a complete SIP submission (CAA section 110(c)(1)), this action is limited to determining whether the covered SIP submissions meet the requirements of CAA section 110(a)(2)(D)(i)(I). For the same reason, comments criticizing specific substantive requirements or implementation timelines in the proposed FIPs are beyond the scope of this action.

2. Requests for Additional Time To Revise SIP Submissions

Comment: Some commenters argue that the EPA must or should delay action on these SIP submissions so that states can reexamine and resubmit SIP submissions. Other commenters argue that states must be given more time to re-examine and resubmit their SIP submission for various reasons, including the substantive requirements in the proposed FIPs.

EPA Response: The EPA notes that there is no support in the Clean Air Act for such a delay. CAA section 110(a)(1) requires states to adopt and submit SIP submissions meeting certain requirements including the requirements of CAA section 110(a)(2)(D)(i)(I), ''within 3 years (or such shorter period as the Administrator prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof).'' CAA section 110(a)(1). The submission deadline clearly runs from the date of promulgation of the NAAQS, which for the 2015 ozone NAAQS was October 1, 2015. 80 FR 65291 (Oct. 26, 2015). In addition, while the Administrator is given authority to prescribe a period shorter than three years for the states to adopt and submit such SIP submissions, the Act does not give the Administrator authority to lengthen the time allowed for CAA section 110(a)(2) submissions. And the EPA would be in violation of court-ordered deadlines if it deferred taking final action beyond January 31, 2023, for all but two of the states covered by this action.[277]

Comments asserting that the EPA must give more time to states to correct deficiencies and re-submit conflict with the controlling caselaw in that they would elevate the maximum timeframes allowable within the procedural framework of CAA section 110 over the attainment schedule of CAA section 181 that the D.C. Circuit has now held multiple times must be the animating focus in the timing of good neighbor obligations. The D.C. Circuit in *Wisconsin* held that states and the EPA are obligated to fully address good neighbor obligations for ozone ''as expeditiously as practical'' and in no event later than the next relevant downwind attainment dates found in CAA section 181(a),[278] and the EPA may not delay implementation of measures necessary to address good neighbor requirements beyond the next applicable attainment date without a showing of impossibility or necessity.[279] Further, the court pointed out that the CAA section 110 schedule of SIP and FIP deadlines is procedural, and while the EPA has complied with the mandatory sequence of actions required under section 110 here, we are mindful of the court's observation that, as compared with the fundamental substantive obligations of title I of the CAA to attain and maintain the NAAQS, the maximum timeframes allotted under section 110 are less ''central to the regulatory scheme[.]'' [280]

Comment: Other comments take the position that states are owed a second opportunity to submit SIP submissions before the EPA takes final action for various reasons, including claims that the EPA failed to issue adequate guidance or is otherwise walking back previously issued guidance. They allege that a state cannot choose controls to eliminate significant contribution until the EPA quantifies the contribution. Other comments argue that the EPA should not or cannot base the disapprovals on alleged shifts in policy that occurred after the Agency received the SIP submissions.

EPA Response: The EPA disagrees that the Agency was required to issue guidance or quantify individual states' level of significant contribution for 2015 ozone NAAQS good neighbor obligations, because as noted in *EME Homer City,* the Supreme Court clearly held that ''nothing in the statute places EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.'' [281] The Agency issued three memoranda in 2018 to provide modeling results and some ideas to states in the development of their SIP submissions. However, certain aspects of those discussions were specifically

[277] The EPA has no court-ordered deadline to take final action on the good neighbor SIP submission from Alabama dated June 21, 2022, or Utah's good neighbor SIP submission.

[278] *Wisconsin,* 938 F.3d at 313–14 (citing *North Carolina,* 531 F.3d at 911–12). On May 19, 2020, the D.C. Circuit in *Maryland,* applying the *Wisconsin* decision, held that the EPA must assess air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for the EPA's denial of a petition under CAA section 126(b). *Maryland,* 958 F.3d at 1203–04.

[279] *See Wisconsin,* 938 F.3d at 320.

[280] *Wisconsin,* 938 F.3d at 322 (''Delaware's argument leans too heavily on the SIP submission deadline. SIP submission deadlines, unlike attainment deadlines, are 'procedural' and therefore not 'central to the regulatory scheme.' '') (citing *Sierra Club,* 294 F.3d at 161).

[281] *EME Homer City,* 572 U.S. at 510.

identified as not constituting agency guidance (especially Attachment A to the March 2018 memorandum, which comprised an unvetted list of outside stakeholders' ideas). Further, states' submissions did not meet the terms of the August or October 2018 memoranda addressing contribution thresholds and maintenance receptors, respectively. (*See* Section V.B for further discussion of these memoranda.) We acknowledge that the EPA reassessed air quality and states' contribution levels through additional modeling before proposing action on these SIP submissions. But that is not in any way an effort to circumvent the SIP/FIP process; rather it is an outcome of the reality that the EPA updated its modeling platform from a 2011 to a 2016 base year and updated its emissions inventory information along with other updates. There is nothing improper in the Agency improving its understanding of a situation before taking action, and the Agency reasonably must be able to act on SIP submissions using the information available at the time it takes such action. Those updates have not uniformly been used to disapprove SIPs—the new modeling for instance supported the approval of Montana's and Colorado's SIPs.[282] Nor has the new modeling prevented states from submitting new SIP submissions based on that modeling. For instance, the State of Alabama withdrew its prior submission in April of 2022, following our proposed disapproval, and submitted a new submission (further updated in June of 2022) analyzing the 2016v2 modeling used at proposal. The EPA is acting on that new submission and evaluating the new arguments the State developed regarding the more recent modeling. Nonetheless, as explained in the EPA's proposed disapproval of Alabama's new submission and in Section IV.A, the new arguments that Alabama has presented in its more recent submission do not lead the EPA to a contrary conclusion that its SIP submission should be approved.[283] This demonstrates two points contrary to commenters' contentions: first, the EPA is following the science and is making nationally consistent determinations at Steps 1 and 2, based on its review of each state's submission; and second, the fact that states made submissions based on the 2011-based modeling results presented in the March 2018 memorandum rather than on the most recent modeling results is not prejudicial to the outcome of the EPA's analysis, as our action on Alabama's more recent submission evaluating the State's arguments with respect to the newer, 2016-based modeling makes clear.

Contrary to commenters' arguments, the EPA had no obligation to issue further guidance, define obligations, or otherwise clarify or attempt to interpret states' responsibilities since the issuance of the 2018 memoranda, prior to acting on these SIP submissions. States themselves were aware or should have been aware of the case law developments in *Wisconsin* and in *Maryland,* which called into question the EPA's use of 2023 as the analytical year in the March 2018 memorandum. Those decisions were issued in 2019 and 2020 respectively, yet no state moved to amend or supplement their SIP submissions with analysis of an earlier analytical year or to otherwise bring their analyses into conformance with those decisions (*e.g.,* through fuller analysis of non-EGU emissions reduction potential or through treatment of international contribution). Given the Supreme Court's 2014 holding in *EME Homer City,* 572 U.S. at 508–510, which reversed a D.C. Circuit holding that the EPA *was* obligated to define good neighbor obligations,[284] states had no reason to expect the EPA would be obligated to issue further guidance to clarify requirements in the wake of those decisions. The EPA agrees with those commenters who point out that states have the first opportunity to assess and address obligations in implementing the NAAQS, but with that understanding in mind, it is notable that prior to the proposed disapprovals in February of 2022, no state moved to amend or supplement their SIP submission as the case law on good neighbor obligations evolved or in response to new modeling information as it became available.

Further, the EPA has evaluated state SIP submissions on the merits of what is contained in the submission, not the use of any particular modeling platform. The EPA disagrees with commenters' assertions that the EPA has proposed disapproval of a state's proposed SIP due to the use of a particular modeling platform. As noted previously, the EPA approved state SIP submissions that have used the earlier modeling. The EPA did not reach its conclusion to disapprove states' SIP submissions based on the use of the 2016v2 emissions platform standing alone. Use of that platform, or any other modeling platform, is not *ipso facto* grounds for disapproval at all. As evident in the proposed disapprovals and summarized in Section IV, the EPA evaluated the SIP submissions based on the merits of the arguments put forward in each SIP submission.

3. Alleged Harm to States Caused by Time Between SIP Submission and the EPA's Action

Comment: Many comments pointed to the EPA's statutory deadlines to take action on the SIP submissions to argue that the EPA's delay harmed the upwind state's interests because now the EPA may conclude they need to reduce their emissions to satisfy their good neighbor obligations in the separate FIP rulemaking whereas had the EPA acted by statutory deadlines using the older modeling, they might have had their SIP submissions approved. Some commenters suggest that the EPA never gave the state SIP submissions the appropriate review or suggest that the EPA's review of the SIP submissions was prejudiced by the FIP it had proposed.

EPA Response: The EPA acknowledges that the Agency's statutory deadlines to take final action on these SIP submissions generally fell in 2020 and 2021. However, the delay in acting caused no prejudice to the upwind states. First, this action to disapprove SIP submissions itself will not impose any requirements or penalties on any state or sources within that state. Second, these delays have primarily had the effect of deferring relief to downwind states and their citizens from excessive levels of ozone pollution under the good neighbor provision. Further, the EPA has generally had a practice of correcting its action on good neighbor SIP submittals if later information indicates that a prior action was in error—thus, it is not the case that simply having obtained an approval based on earlier modeling would have meant a state would be forever insulated from later being subject to corrective or remedial good neighbor actions. *See, e.g.,*86 FR 23056, 23067–68 (April 30, 2021) (error correcting Kentucky's approval to a disapproval and promulgating FIP addressing Kentucky's outstanding 2008 ozone NAAQS good neighbor obligations); 87 FR 20036, 20041 (April 6, 2022) (proposing error correction for Delaware's 2015 ozone NAAQS SIP approval to a disapproval based on updated air quality modeling). Finally, there is no basis in the CAA to use the Agency's own delay as a basis to nullify

[282] 87 FR 6095, 6097 at n. 15 (February 3, 2022) (Montana proposal); 87 FR 27050, 27056 (May 6, 2022) (Colorado, proposal), 87 FR 61249 (October 11, 2022) (Colorado, final).

[283] 87 FR 64412 (October 25, 2022).

[284] *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012) (*EME Homer City I*).

the authority granted in the Act to address the nation's air pollution problems, as the statute itself contains other forms of adequate remedy. CAA section 304(a)(2) provides for judicial recourse where there is an alleged failure by the agency to perform a nondiscretionary duty, and that recourse is for the Agency to be placed on a court-ordered deadline to address the relevant obligations. *Accord Oklahoma,* 723 F.3d at 1223–24; *Montana Sulphur and Chemical Co.* v. *U.S. EPA,* 666 F.3d 1174, 1190–91 (9th Cir. 2012).

Comment: Some comments contend that the EPA's delay in acting on SIP submissions was a deliberate attempt to circumvent the SIP/FIP process, unduly burden the states, or to defer making information available to states. Comments allege that the EPA intentionally stalled an evaluative action until the perceived ''facts'' of the situation changed such that the analyses submitted by states were rendered outdated.

EPA Response: The EPA disagrees with both allegations. In this respect, it is important to review the recent history of the EPA's regulatory actions and litigation with respect to good neighbor obligations for both the 2008 and 2015 ozone NAAQS, and in particular, the substantial additional workload the Agency took on in the wake of the remand of the CSAPR Update in *Wisconsin.* In 2018, as the EPA issued the memoranda cited by commenters and planned to shift its focus to implementing the 2015 standards, it also issued the CSAPR Close-out, which made an analytical finding that there were no further obligations for 21 states for the 2008 standards following the CSAPR Update. 83 FR 65878 (Dec. 21, 2018). However, contrary to the EPA's understanding that it had fully addressed good neighbor obligations for the 2008 ozone NAAQS, the D.C. Circuit's decisions in *Wisconsin* (remanding the CSAPR Update) and in *New York* (vacating the CSAPR Close-out), forced the Agency to quickly pivot back to addressing remaining obligations under the 2008 standards. *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019); *New York* v. *EPA,* 781 F. App'x. 4 (D.C. Cir. 2019). The EPA was subject to renewed deadline suit litigation under CAA section 304, which led to a March 15, 2021, deadline to take final action on several states whose FIPs had been remanded and were incomplete in the wake of the CSAPR Close-out vacatur. *New Jersey* v. *Wheeler,* 475 F.Supp.3d 308 (S.D.N.Y. 2020). Throughout 2020 and 2021, the EPA was therefore focused on an unexpected rulemaking obligation to complete good neighbor requirements as to the states with remanded CSAPR Update FIPs. This led to the EPA proposing and then issuing an economically significant, major rule assessing additional EGU emissions reduction obligations as well as presenting updated air quality modeling analysis using novel techniques and presenting information on a host of non-EGU industrial sources for the first time, *i.e.,* the Revised CSAPR Update, 86 FR 23054 (April 30, 2021). That rule is now currently subject to judicial review in the D.C. Circuit, *Midwest Ozone Group* v. *EPA,* No. 21–1146 (D.C. Cir. argued Sept. 28, 2022).[285] The EPA has also been in the process of reviewing and acting upon many states' good neighbor SIPs where the available information indicates that an approval of the state's submission was appropriate.[286]

Finally, the Agency needed time to review and evaluate the SIP submissions in a coordinated fashion to act on all the states' submissions in a consistent manner. As the EPA explained in the proposed disapproval action, consistency in defining CAA obligations is critically important in the context of addressing a regional-scale pollutant like ozone. *See, e.g.,* 87 FR 9807 n.48. Through coordinated development of the bases for how the Agency could act on the SIP submissions, while also evaluating the contours of a potential Federal plan to implement obligations where required, the EPA sequenced its deliberations and decision making to maximize efficient, consistent, and timely action, in recognition of the need to implement any necessary obligations ''as expeditiously as practicable.''[287] The downsides of commenters' policy preference in favor of giving states another opportunity to develop SIP submissions, or in first acting on each SIP submission before proposing a FIP, are that such a sequence of actions would have led to multiple years of additional delay in addressing good neighbor obligations. Even if such a choice was available to the Agency using the CAA section 110(k)(5) SIP call mechanism, it was entirely reasonable for the EPA to decline to use that mechanism in this instance. (EPA further addresses comments in support of a SIP call approach in the RTC document.)

In short, commenters' notion that the EPA was deliberately or intentionally deferring or delaying action on these SIP submissions to circumvent any required legal process or reach any specific result is simply incorrect. Commenters have not supplied any evidence to support the claim either that any legal process was circumvented or that the Agency's conduct was in bad faith. *See Biden* v. *Texas,* 142 S.Ct. 2528, 2546–47 (2022) (presumption of regularity attends agency action absent a ''strong showing of bad faith or improper behavior'') (citing *Citizens to Protect Overton Park* v. *Volpe,* 401 U.S. 302, 420 (1971); *SEC* v. *Chenery,* 318 U.S. 80, 87 (1943)).

4. Use of Updated Modeling

Comment: Comments allege that by relying on modeling not available at the time of SIP submission development, the EPA ''moved the goal post.'' Comments note the timeframes set out for action on SIPs, citing section 110 of the Act, and allege that by failing to act on SIP submissions in a timely manner and basing such actions on new modeling, the EPA imposes an arbitrary and capricious standard. Comments state that the EPA should not disapprove a SIP based on data not available to states during development of the SIP submissions or to the EPA during the period statutorily allotted for the EPA to take final action on SIP submissions.

EPA Response: In response to comments' claims that the EPA has inappropriately changed states' obligations for interstate transport by relying on updated modeling not available to states at the time they prepared their SIP submissions, the EPA disagrees. As an initial matter, the EPA disagrees with comment's claiming that the agency expected state air agencies to develop a SIP submission based on

[285] During this time, the EPA also fulfilled its obligations to act on several petitions brought by downwind states under section 126(b) of the CAA. These actions culminated in litigation and ultimately adverse decisions in *Maryland* and *New York* v. *EPA. Maryland v,* 958 F.3d; *New York* v. *EPA,* 964 F.3d 1214, 2020 WL 3967838 (D.C. Cir. 2020). Further review and action on these remands remains pending before the agency.

[286] In chronological order: 83 FR 47568 (September 20, 2018) (Washington); 84 FR 69331 (December 18, 2019) (Alaska); 84 FR 22376 (May 17, 2019) (Oregon); 85 FR 5570 (January 31, 2020) (Washington, DC); 85 FR 5572 (January 31, 2020) (Massachusetts); 85 FR 20165 (April 10, 2020) (North Dakota); 85 FR 21325 (April 17, 2020) (Nebraska); 85 FR 25307 (May 1, 2020) (Delaware); 85 FR 34357 (June 4, 2020) (Vermont); 85 FR 65722 (October 16, 2020) (Idaho); 85 FR 67653 (October 26, 2020) (South Dakota); 86 FR 45870 (August 17, 2021) (Maine and New Hampshire); 86 FR 68413 (December 2, 2021) (Florida, Georgia, North Carolina, and South Carolina); 86 FR 70409 (December 10, 2021) (Rhode Island); 86 FR 71830 (December 20, 2021) (Connecticut); 86 FR 73129 (December 27, 2021) (Hawaii); 87 FR 19390 (April 4, 2022) (Kansas); 87 FR 21578 (April 12, 2022) (Montana); 87 FR 22463 (April 15, 2022) (Iowa); and 87 FR 61249 (October 11, 2022) (Colorado).

[287] CAA section 181(a); *Wisconsin,* 938 F.3d at 313–14 (citing *North Carolina,* 531 F.3d at 911–12).

some unknown future data. The EPA recognizes that states generally developed their SIP submissions with the best available information at the time of their development. As stated in the proposals, the EPA did not evaluate states' SIP submissions based solely on the 2016v2 emissions platform (or the 2016v3 platform, which incorporates comments generated during the public comment period on the proposed SIP actions and which supports these final SIP disapproval actions). We evaluated the SIP submissions based on the merits of the arguments put forward in each SIP submission, which included any analysis put forward by states to support their conclusions. Thus, we disagree with commenters who allege the Agency has ignored the information provided by the states in their submissions. Indeed, the record for this action reflects our extensive evaluation of states' air quality and contribution analyses. *See* generally Section IV, which summarizes our evaluation for each state.

We disagree with commenters who advocate that the EPA's evaluation of these submissions must be limited to the information available to states at the time they made their submissions, or information at the time of the deadline for the EPA to act on their submissions. It can hardly be the case that the EPA is prohibited from taking rulemaking action using the best information available to it at the time it takes such action. Nothing in the CAA suggests that the Agency must deviate from that general principle when acting on SIP submissions. While CAA section 110(k)(2) specifies a time period in which the Administrator is to act on a state submission, neither this provision nor any other provision of the CAA specifies that the remedy for the EPA's failure to meet a statutory deadline is to arrest or freeze the information the EPA may consider to what was available at the time of a SIP submission deadline under CAA section 110. Indeed, in the interstate transport context, this would lead to an anomalous result. For example, the D.C. Circuit rejected an argument made by Delaware against the CSAPR Update air quality analysis that the EPA was limited to reviewing air quality conditions in 2011 (rather than 2017) at the time of the statutory deadline for SIP submittals. The court explained,

> Delaware's argument leans too heavily on the SIP submission deadline. SIP submission deadlines, unlike attainment deadlines, are ''procedural'' and therefore not ''central to the regulatory scheme.'' *Sierra Club,* 294 F.3d at 161. Nor can Delaware's argument be reconciled with the text of the Good Neighbor Provision, which prohibits upwind States from emitting in amounts ''which *will*'' contribute to downwind nonattainment. 42 U.S.C. 7410(a)(2)(D)(i) (emphasis added). Given the use of the future tense, it would be anomalous for EPA to subject upwind States to good neighbor obligations in 2017 by considering which downwind States were once in nonattainment in 2011.

Wisconsin, 903 F.3d at 322. By the same token, here, holding the EPA to a consideration only of what information states had available regarding the 2023 analytic year at the time of their SIP submissions or at the time of a deadline under CAA section 110, would likewise elevate the ''procedural'' deadlines of CAA section 110 above the substantive requirements of the CAA that are ''central to the regulatory scheme.'' Doing so here would force the Agency to act on these SIP submissions knowing that more recent refined, high quality, state-of-the-science modeling and monitoring data would produce a different result in our forward-looking analysis of 2023 than the information available in 2018. Nothing in the CAA dictates that the EPA must be forced into making substantive errors in its good neighbor analysis on this basis.

We relied on CAMx Version 7.10 and the 2016v2 emissions platform to make updated determinations regarding which receptors would likely exist in 2023 and which states are projected to contribute above the contribution threshold to those receptors. As explained in the preamble of the EPA's proposed actions and further detailed in the document titled ''Air Quality Modeling TSD: 2015 Ozone National Ambient Air Quality Standards Proposed Interstate Transport Air Plan Disapproval'' and 2016v2 Emissions Inventory TSD, both available in Docket ID no. EPA–HQ–OAR–2021–0663, the 2016v2 modeling built off previous modeling iterations used to support the EPA's action on interstate transport obligations. The EPA continuously refines its modeling to ensure the results are as indicative as possible of air quality in future years. This includes adjusting our modeling platform and updating our emissions inventories to reflect current information.

Additionally, we disagree with comments claiming that the 2016v2 modeling results were sprung upon the states with the publication of the proposed disapprovals. The EPA has been publishing a series of data and modeling releases beginning as early as the publication of the 2016v1 modeling with the proposed Revised CSAPR Update in November of 2020, which could have been used to track how the EPA's modeling updates were potentially affecting the list of possible receptors and linkages for the 2015 ozone NAAQS in the 2023 analytic year. The 2016-based meteorology and boundary conditions used in the modeling have been available through the 2016v1 platform, which was used for the Revised CSAPR Update (proposed in November of 2020, 85 FR 68964). The updated emissions inventory files used in the current modeling were publicly released September 21, 2021, for stakeholder feedback, and have been available on our website since that time.[288] The CAMx modeling software that the EPA used has likewise been publicly available for over a year. CAMx version 7.10 was released by the model developer, Ramboll, in December 2020. On January 19, 2022, we released on our website and notified a wide range of stakeholders of the availability of both the modeling results for 2023 and 2026 (including contribution data) along with many key underlying input files.[289]

By providing the 2016 meteorology and boundary conditions (used in the 2016v1 version) in fall of 2020, and by releasing updated emissions inventory information used in 2016v2 in September of 2021,[290] states and other interested parties had multiple opportunities prior to the proposed disapprovals in February of 2022 to consider how our modeling updates could affect their status for purposes of evaluating potential linkages for the 2015 ozone NAAQS. Further, by using the updated modeling results, the EPA is using the most current and technically appropriate information for this rulemaking. This modeling was not performed to ''move the goal posts'' for states but meant to provide updated emissions projections, such as additional emissions reductions for EGUs following promulgation of the Revised CSAPR Update for the 2008 ozone NAAQS, more recent information on plant closures and fuel switches, and sector trends, including non-EGU sectors. The construct of the 2016v2 emissions platform is described in the 2016v2 Emissions Modeling TSD contained in Docket ID No. EPA–HQ–OAR–2021–0663.

Finally, comments related to the timing of the EPA's action to disapprove these SIP submissions are addressed in Section V.A.1. The EPA notes the statute provides a separate remedy for agency action unlawfully delayed. In section 304 of the CAA, there is a

[288] *See https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

[289] *See https://www.epa.gov/scram/photochemical-modeling-applications.*

[290] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

process for filing suit against the EPA for its failure to comply with a non-discretionary statutory duty under the CAA. The appropriate remedy in such cases is an order to compel agency action, not a determination that the agency, by virtue of missing a deadline, has been deprived of or constrained in its authority to act. *See Oklahoma,* 723 F.3d at 1224 (''[W]hen 'there are less drastic remedies available for failure to meet a statutory deadline'—such as a motion to compel agency action—'courts should not assume that Congress intended the agency to lose its power to act.' The Court 'would be most reluctant to conclude that every failure of an agency to observe a procedural requirement voids subsequent agency action, especially when important public rights are at stake.''') (cleaned up) (quoting *Brock* v. *Pierce County,* 476 U.S. 253, 260 (1986)).

Comment: Comments state that it is inappropriate for the EPA to revise its emissions inventory and to conduct new air quality modeling without allowing an appropriate opportunity for stakeholder review and comment and that the EPA must allow public comment on any updated (*i.e.,* 2016v3) modeling prior to use by the EPA in a final action. Comments claim that the EPA must withdraw the proposed disapproval and provide states time to develop new SIP submissions based on the updated information.

EPA Response: The EPA has evaluated a wide range of technical information and critiques of its 2016v2 emissions inventory and modeling platform following a solicitation of public feedback as well the public comment period on this action (and the proposed FIP action) and has responded to those comments and incorporated updates into the version of the modeling being used in this final action (2016v3). *See* Section III, the Final Action AQM TSD, and Section 4 of the RTC document for further discussion.

The EPA's development of and reliance on newer modeling to confirm modeling used at the proposal stage is in no way improper and is simply another iteration of the EPA's longstanding scientific and technical work to improve our understanding of air quality issues and causes going back decades. Where the 2016v3 modeling produced a potentially different outcome for states from proposal, that is reflected in this action (*e.g.,* our deferral of final action on Tennessee and Wyoming's SIP submissions).

Comment: Comments allege that EPA's modeling results have been inconsistent, questioning the reliability of the results.

EPA Response: Although some commenters indicate that our modeling iterations have provided differing outcomes and are therefore unreliable, this is not what the overall record indicates. Rather, in general, although the specifics of states' linkages may change slightly, our modeling overall has provided consistent outcomes regarding which states are linked to downwind air quality problems. For example, the EPA's modeling shows that most states that were linked to one or more receptors using the 2011-based platform (*i.e.,* the March 2018 data release) are also linked to one or more receptors using the newer 2016-based platform. Because each platform uses different meteorology (*i.e.,* 2011 and 2016) it is not at all unexpected that an upwind state could be linked to different receptors using 2011 versus 2016 meteorology.

In addition, although a state may be linked to a different set of receptors, states are often linked to receptors in the same area that has a persistent air quality problem. These differing results regarding receptors and linkages can be affected by the varying meteorology from year to year, but this does not indicate that the modeling or the EPA or the state's methodology for identifying receptors or linkages is inherently unreliable. Rather, for many states these separate modeling runs all indicated: (i) that there would be receptors in areas that would struggle with nonattainment or maintenance in the future, and (ii) that the state was linked to some set of these receptors, even if the receptors and linkages differed from one another in their specifics (*e.g.,* a different set of receptors were identified to have nonattainment or maintenance problems, or a state was linked to different receptors in one modeling run versus another).

The EPA interprets this common result as indicative that a state's emissions have been substantial enough to generate linkages at Step 2 to varying sets of downwind receptors generated under varying assumptions and meteorological conditions, even if the precise set of linkages changed between modeling runs. Under these circumstances, we think it is appropriate to proceed to a Step 3 analysis to determine what portion of a particular state's emissions should be deemed ''significant.'' We also note that only four states included in the proposed disapprovals went from being unlinked to being linked between the 2011-based modeling provided in the March 2018 memorandum and the 2016v2-based modeling—Alabama, Minnesota, Nevada, and Tennessee.

5. Cooperative Federalism and the EPA's Authority

Comment: Many comments point to the concept of cooperative federalism as embodied in the CAA to make various arguments as to why the EPA cannot or should not be allowed to exercise its independent judgment in evaluating the arguments presented by the states in the SIP submissions, and some also argue that the EPA must approve each state's submission in deference to how states choose to interpret the CAA requirements they must meet.

EPA Response: The CAA establishes a framework for state-Federal partnership to implement the NAAQS based on cooperative federalism. Under the general model of cooperative federalism, the Federal Government establishes broad standards or goals, states are given the opportunity to determine how they wish to achieve those goals, and if states choose not to or fail to adequately implement programs to achieve those goals, a Federal agency is empowered to directly regulate to achieve the necessary ends. Under the CAA, once the EPA establishes or revises a NAAQS, states have the obligation and opportunity in the first instance to develop an implementation plan under CAA section 110 and the EPA will approve SIP submissions under CAA section 110 that fully satisfy the requirements of the CAA. This sequence of steps is not in dispute.

The EPA does not, however, agree with the comments' characterization of the EPA's role in the state-Federal relationship as being ''secondary'' such that the EPA must defer to state choices heedless of the substantive objectives of the Act; such deference would be particularly inappropriate in the context of addressing interstate pollution. The EPA believes that the comments fundamentally misunderstand or inaccurately describe this action, as well as the '''division of responsibilities' between the states and the federal government'' they identify in CAA section 110 citing the *Train-Virginia* line of cases [291] and other cases.[292]

[291] *See Virginia* v. *EPA,* 108 F.3d 1397, 1407 (D.C. Cir. 1997) (*Virginia*) (quoting *Train* v. *Natural Resources Defense Council, Inc.*, 421 U.S. 60, 79 (1975) (*Train*)). The ''Train-Virginia line of cases'' are named for the U.S. Supreme Court case *Train,* 421 U.S. and to the D.C. Circuit case *Virginia,* 108 F.3d. The D.C. Circuit has described these cases as defining a ''federalism bar'' that generally recognizes states' ability to select emissions control measures in their SIPs so long as CAA requirements are met. *See, e.g., Michigan* v. *EPA,* 213 F.3d 663, 687 (D.C. Cir. 2000) (*Michigan*).

[292] *Union Elec. Co.* v. *EPA,* 427 U.S. 246 (1976), *Am. Elec. Power Co.* v. *Connecticut,* 565 U.S. 410 (2011), *Fla. Power & Light* v. *Costle,* 650 F.2d 579

Continued

Those cases, some of which pre-date the CAA amendments of 1990 resulting in the current Good Neighbor Provision,[293] stand only for the proposition that the EPA must approve state plans *if* they meet the applicable CAA requirements. But these cases say nothing about what those applicable requirements are. The EPA is charged under CAA section 110 with reviewing states' plans for compliance with the CAA and approving or disapproving them based on EPA's determinations. Thus, the EPA must ultimately determine whether state plans satisfy the requirements of the Act or not. Abundant case law reflects an understanding that the EPA must evaluate SIP submissions under the CAA section 110(k)(2) and (3).[294] If they are deficient, the EPA must so find, and become subject to the obligation to directly implement the relevant requirements through a Federal implementation plan under CAA section 110(c), unless EPA approves an applicable SIP first.[295]

The EPA responds in greater detail to these comments in the RTC document.

6. Availability of Guidance for SIP Submissions

Comment: Comments contend the EPA failed to issue guidance in a timely fashion by releasing its August 2018 memorandum 31 days prior to when SIPs addressing interstate ozone transport were due and issuing the October 2018 memorandum 18 days after those SIPs were due. Some comments additionally claim that it is unreasonable for the EPA to disapprove SIP submissions based on standards that were not defined, mandated, or required by official guidance.

EPA Response: Comments' contention is unsupported by the statute or applicable case law. Regarding the need for the EPA's guidance in addressing good neighbor obligations, in *EME Homer City,* the Supreme Court clearly held that ''nothing in the statute places the EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.''[296]

Nonetheless, as comments point out, the EPA issued three ''memoranda'' in 2018 to provide some assistance to states in developing these SIP submissions. In acting on the SIP submissions in this action, the EPA is neither rescinding nor acting inconsistently with the memoranda—to the extent the memoranda constituted agency guidance (not all the information provided did constitute guidance), information or ideas in the memoranda had not at that time been superseded by case law developments, and the memoranda's air quality and contribution data had not at that time been overtaken by updated modeling and other updated air quality information. While comments specific to each of those memoranda are addressed elsewhere in this record, we note in brief that each memorandum made clear that the EPA's action on SIP submissions would be through a separate notice-and-comment rulemaking process and that SIP submissions seeking to rely on or take advantage of any information or concepts in these memoranda would be carefully reviewed against the relevant legal requirements and technical information available to the EPA at the time it would take such rulemaking action.

B. Application of the 4-Step Interstate Transport Framework

1. Analytic Year

Comment: One comment asserted that 2023 is not an appropriate analytical year because, according to the commenter, the EPA and at least some downwind states have not in fact implemented mandatory emissions control requirements associated with their nonattainment areas, and *North Carolina* and *Wisconsin* require that upwind and downwind state obligations must be implemented ''on par.'' The comment also characterizes the EPA's invocation of *Maryland* as an inappropriate shifting of regulatory burden to upwind states.

EPA Response: This is an incorrect interpretation of the D.C. Circuit's holdings in *North Carolina, Wisconsin,* and *Maryland,* which held that the EPA and the states must align good neighbor obligations to the extent possible with the downwind areas' attainment dates. These are set by the statute and remain fixed regardless of whether downwind areas are delayed in implementing their own obligations. It would be unworkable to expect that upwind states' obligations could be perfectly aligned with each downwind area's actual timetable for implementing the relevant emissions controls, and no court has held that this is the EPA's or the states' obligation under the good neighbor provision. Further, this ignores the fact that upwind states must also address their interference with maintenance of the NAAQS, as well as the *Maryland* court's holding that good neighbor obligations should be addressed by the Marginal area attainment date for ozone under subpart 2 of part D of title I of the CAA. Both circumstances may involve situations in which the home state for an identified downwind receptor does not have a specific obligation to plan for and implement specific emissions controls while an upwind state may nonetheless be found to have good neighbor obligations. But, as the *Maryland* court recognized, the absence of specific enumerated requirements does not mean the downwind state does not have a statutorily binding obligation subject to burdensome regulatory consequences: ''Delaware must achieve attainment 'as expeditiously as practicable,''' and ''an upgrade from a marginal to a moderate nonattainment area carries significant consequences . . . .'' *Maryland,* 958 F.3d at 1204.

Further, where any downwind-state delays are unreasonable or violate statutory timeframes, the CAA provides recourse to compel the completion of such duties in CAA section 304, not to defer the elimination of significant contribution and thereby expose the public in downwind areas to the elevated pollution levels caused in part by upwind states' pollution. Regardless, in this action, 2023 aligns with the Moderate area attainment date in 2024, and all of the downwind nonattainment areas corresponding to receptor locations identified at Step 1 in this action are already classified as being in Moderate nonattainment or have been reclassified to Moderate and the relevant states face obligations to submit

(5th Cir. 1981), *Bethlehem Steel Corp.* v. *Gorsuch,* 742 F.2d 1028 (7th Cir. 1984), *Concerned Citizens of Bridesburg* v. *EPA,* 836 F.2d 777 (3d Cir. 1987), *North Carolina,* 531 F.3d 896, *Luminant,* 675 F.3d 917 (5th. Cir. 2012), *Luminant Co. LLC* v. *EPA,* 714 F.3d 841 (5th. Cir. 2013), *North Dakota* v. *EPA,* 730 F.3d 750 (8th. Cir. 2013), *EME Homer City II,* 795 F.3d 118 (D.C. Cir. 2015), and *Texas* v. *USEPA,* 829 F.3d 405 (5th. Cir. 2016).

[293] The 1970 version of the Act required SIPs to include ''adequate provisions for intergovernmental cooperation'' concerning interstate air pollution. CAA section 110(a)(2)(E), 84 Stat. 1681, 42 U.S.C. 1857c–5(a)(2)(E). In 1977, Congress amended the Good Neighbor Provision to direct States to submit SIP submissions that included provisions ''adequate'' to ''prohibi[t] any stationary source within the State from emitting any air pollutant in amounts which will . . . prevent attainment or maintenance [of air quality standards] by any other State.'' CAA section 108(a)(4), 91 Stat. 693, 42 U.S.C. 7410(a)(2)(E) (1976 ed., Supp. II). Congress again amended the Good Neighbor Provision in 1990 to its current form.

[294] *See, e.g., Virginia,* 108 F.3d at 1406. *See also, e.g., Westar Energy* v. *EPA,* 608 Fed. App'x 1, 3 (D.C. Cir. 2015) (''EPA acted *well within the bounds* of its delegated authority when it disapproved of Kansas's proposed [good neighbor] SIP.'') (emphasis added); *Oklahoma,* 723 F.3d at 1209 (upholding the EPA's disapproval of ''best available retrofit technology'' (BART) SIP, noting BART ''does not differ from other parts of the CAA—states have the ability to create SIPs, but they are subject to EPA review'').

[295] *EME Homer City Generation,* 572 U.S. at 508–510.

[296] *EME Homer City,* 572 U.S. at 510.

SIP submissions and implement reasonably available control technologies (RACT) by January 1, 2023. *See* 87 FR 60897, 60899 (October 7, 2022). The EPA further responds to this comment in the RTC document.

2. Attachment A to the March 2018 Memorandum

Comment: Comments state that states conducted their analyses based on the flexibilities listed in Attachment A of the March 2018 Memorandum. Comments cite the part of the memorandum where the EPA notes that ''in developing their own rules, states have flexibility to follow the familiar four-step transport framework (using [the] EPA's analytical approach or somewhat different analytical approaches within these steps) or alternative frameworks, so long as their chosen approach has adequate technical justification and is consistent with the requirements of the CAA.'' Comments state that the EPA's disapproval of SIP submissions that took advantage of the flexibilities is arbitrary and capricious because the EPA has changed, without communication, its consideration of what is deemed to be the ''necessary provisions'' required for an approvable SIP submission too late in the SIP submission process and because, in disapproving these SIPs, the EPA is applying a consistent set of policy judgments across all states.

EPA Response: Comments mistakenly view Attachment A to the March 2018 memorandum releasing modeling results as constituting agency guidance. The EPA further disagrees with commenters' characterization of the EPA's stance regarding the ''flexibilities'' listed (without analysis) in Attachment A. Attachment A to the March 2018 memorandum identified a ''Preliminary List of Potential Flexibilities'' that could potentially inform SIP development.[297] However, the EPA made clear in that attachment that the list of ideas were not suggestions endorsed by the Agency but rather ''comments provided in various forums'' from outside parties on which the EPA sought ''feedback from interested stakeholders.'' [298] Further, Attachment A stated, ''EPA is not at this time making any determination that the ideas discussed later are consistent with the requirements of the CAA, nor are we specifically recommending that states use these approaches.'' [299] Attachment A to the March 2018 memorandum, therefore, does not constitute agency guidance, but was intended to generate further discussion around potential approaches to addressing ozone transport among interested stakeholders. The EPA emphasized in this memorandum that any such alternative approaches must be technically justified and appropriate in light of the facts and circumstances of each particular state's submittal.[300] As stated in the proposed SIP disapprovals,[301] the March 2018 memorandum provided that, ''While the information in this memorandum and the associated air quality analysis data could be used to inform the development of these SIPs, the information is not a final determination regarding states' obligations under the good neighbor provision.'' [302] In this final SIP disapproval action, the EPA again affirms that certain concepts included in Attachment A to the March 2018 memorandum require unique consideration, and these ideas do not constitute agency guidance with respect to transport obligations for the 2015 ozone NAAQS.

In response to comments' claims that since the time transport SIP submissions were submitted to the EPA for review, the EPA has changed, without communication, its consideration of what is deemed to be the ''necessary provisions'' required for an approvable SIP submission, the EPA disagrees. As comments note, and as stated in the proposed disapproval notifications, the EPA recognizes that states have discretion to develop their own SIP transport submissions and agrees that states are not bound to using the 4-step interstate transport framework the EPA has historically used. However, states must then provide sufficient justification and reasoning to support their analytical conclusions and emissions control strategies. *See, e.g.,* 87 FR 9798, 9801. In the SIP submissions being disapproved in this action, no state provided any enforceable emissions control strategies for approval into their SIP. The EPA has evaluated the merits of each state's arguments as to why no additional emissions reduction requirements are needed to satisfy their obligations under CAA section 110(a)(2)(D)(i)(I) for the more protective 2015 ozone NAAQS. While the EPA used its own 4-step interstate transport framework as a guide for its review to ensure a consistent and equitable evaluation of each states' submissions, the EPA has also considered states' individual arguments without predetermining the EPA's conclusions about the state's transport obligations.

It was never the Agency's intent in sharing Attachment A that states would invoke one or more of the potential ''flexibilities'' that outside parties advocated for as a basis for concluding that no additional emissions controls were necessary to address interstate transport for the more protective 2015 ozone NAAQS without proper justification. Nothing in Attachment A suggested that was the Agency's intended objective. Indeed, where certain approaches identified in Attachment A might have produced analytical conclusions requiring upwind states to reduce their emissions, no state invoking Attachment A followed through with implementing those controls. We observe this dynamic at work in Kentucky's submission, because Kentucky appended comments from the Midwest Ozone Group to its submission that demonstrated that applying a ''weighted'' approach to allocating upwind-state responsibility at Step 3 would have resulted in an emissions control obligation on Kentucky's sources, yet the State offered no explanation in its submittal why it was not adopting that approach or even what its views on that approach were. *See* 87 FR 9515. As another example, Michigan cited Attachment A to the March 2018 in developing a methodology for calculating significant contribution under which Michigan would have been responsible for eliminating up to 0.12 ppb of contribution to downwind receptors; however, the State suggested that uncertainty caused by modeling ''noise'' was too great to either require emissions reductions or demonstrate that Michigan had any linkages to receptors at all. *See* 87 FR 9860–9861. However, this explanation did not, as an analytical matter, demonstrate a level of scientific uncertainty which might allow for ignoring the results,[303]

[297] March 2018 memorandum, Attachment A.

[298] *Id.*

[299] *Id.*

[300] March 2018 memorandum.

[301] E.g., 87 FR 9487.

[302] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), March 27, 2018, available in docket EPA–HQ–OAR–2021–0663 or at *https://www.epa.gov/interstate-air-pollution-transport/interstate-air-pollution-transport-memos-and-notices.*

[303] Scientific uncertainty may only be invoked to avoid comporting with the requirements of the CAA when ''the scientific uncertainty is so profound that it precludes . . . reasoned judgment'' *Massachusetts* v. *EPA,* 127 S.Ct. 1438 (2007). *See Wisconsin,* 938 F.3d at 318–19 (''Scientific uncertainty, however, does not excuse EPA's failure to align the deadline for eliminating upwind States' significant contributions with the deadline for downwind attainment of the NAAQS.''). *See also EME Homer City,* 795 F.3d at 135–36 (''We will not invalidate EPA's predictions solely because there might be discrepancies between those predictions

Continued

particularly when the Agency has implemented good neighbor requirements at levels of ''significant contribution'' comparable to or even less than 0.12 ppb. *See Wisconsin,* 938 F.3d at 322–23 (rejecting Wisconsin's argument that it should not face good neighbor obligations for the 2008 ozone NAAQS on the basis that its emission reductions would only improve a downwind receptor by two ten-thousandths of a part per billion).

The EPA continues to neither endorse the ''flexibilities'' in Attachment A, nor stakes a position that states are precluded from relying on these concepts in the development of their good neighbor SIP submissions, assuming they could be adequately justified both technically and legally. This has been demonstrated through the EPA's extensive evaluation of the merits of each states' SIP submissions, including their attempted use of flexibilities and derivatives of the EPA's historically applied 4-step interstate transport framework.[304]

3. Step 1: October 2018 Memorandum

Comments: Comments claimed that the EPA is not honoring its October 2018 memorandum, which they claim would allow for certain monitoring sites identified as maintenance-only receptors in the EPA's methodology to be excluded as receptors based on historical data trends. They assert that the EPA is inappropriately disapproving SIP submissions where the state sufficiently demonstrated certain monitoring sites should not be considered to have a maintenance problem in 2023.

EPA Response: The October 2018 memorandum recognized that states may be able to demonstrate in their SIPs that conditions exist that would justify treating a monitoring site as not being a maintenance receptor despite results from our modeling methodology identifying it as such a receptor. The EPA explained that this demonstration could be appropriate under two circumstances: (1) the site currently has ''clean data'' indicating attainment of the 2015 ozone NAAQS based on measured air quality concentrations, or (2) the state believes there is a technical reason to justify using a design value from the baseline period that is lower than the maximum design value based on monitored data during the same baseline period. To justify such an approach, the EPA anticipated that any such showing would be based on an analytical demonstration that: (1) Meteorological conditions in the area of the monitoring site were conducive to ozone formation during the period of clean data or during the alternative base period design value used for projections; (2) ozone concentrations have been trending downward at the site since 2011 (and ozone precursor emissions of NO_X and VOC have also decreased); and (3) emissions are expected to continue to decline in the upwind and downwind states out to the attainment date of the receptor. EPA evaluated state's analyses and found no state successfully applied these criteria to justify the use of one of these alternative approaches. The air quality data and projections in Section III indicate that trends in historic measured data do not necessarily support adopting a less stringent approach for identifying maintenance receptors for purposes of the 2015 ozone NAAQS. In fact, as explained in Section III, the EPA has found in its analysis for this final action that, in general, recent measured data from regulatory ambient air quality ozone monitoring sites suggest a number of receptors with elevated ozone levels will persist in 2023 even though our traditional methodology at Step 1 did not identify these monitoring sites as receptors in 2023. Thus, the EPA is not acting inconsistently with that memorandum—the factual conditions that would need to exist for the suggested approaches of that memorandum to be applicable have not been demonstrated as being applicable or appropriate based on the relevant data.

We further respond to comments related to the identification of receptors at Step 1 the RTC document.

4. Step 2: Technical Merits of a 1 Percent of the NAAQS Contribution Threshold

Comment: Several comments contend that for technical reasons, the 0.70 ppb threshold is inappropriate for determining whether a state is linked to a downwind receptor at Step 2 of the 4-step interstate transport framework. Comments state that the degree to which errors exist in modeling ozone concentrations and contributions make it inappropriate for a threshold as low as 0.70 ppb to be used. Some comments further state that the 0.70 ppb threshold is inappropriate because the concentration threshold is lower than what monitoring devices are capable of detecting. Comments reference the reported precision of Federal reference monitors for ozone and the rounding requirements found in 40 CFR part 50, appendix U, Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone, for support. Comments note that the 1 percent contribution threshold of 0.70 ppb is lower than the manufacturer's reported precision of Federal reference monitors for ozone and that the requirements found in appendix U truncates monitor values of 0.70 ppb to 0 ppb.

EPA Response: The EPA disagrees that a 1 percent of the NAAQS contribution threshold at Step 2 is ''inappropriate'' for the 2015 ozone NAAQS due to modeling biases and errors. The explanation for how the 1 percent contribution threshold was originally derived is available in the 2011 CSAPR rulemaking. *See* 76 FR 48208, 48236–38 (Aug. 8, 2011). The EPA has effectively applied a 1 percent of the NAAQS threshold to identify linked upwind states in three prior FIP rulemakings and numerous state-specific actions. The D.C. Circuit has declined to establish bright line criteria for model performance. In upholding the EPA's approach to evaluating interstate transport in CSAPR, the D.C. Circuit held that it would not ''invalidate EPA's predictions solely because there might be discrepancies between those predictions and the real world. That possibility is inherent in the enterprise of prediction.'' *EME Homer City II,* 795 F.3d at 135. The court continued to note that ''the fact that a 'model does not fit every application perfectly is no criticism; a model is meant to simplify reality in order to make it tractable.' '' *Id.* at 135–36 (quoting *Chemical Manufacturers Association* v. *EPA,* 28 F.3d 1259, 1264 (DC Cir. 1994). *See also Sierra Club* v. *EPA,* 939 F.3d 649, 686–87 (5th Cir. 2019) (upholding the EPA's modeling in the face of complaints regarding an alleged ''margin of error,'' noting challengers face a ''considerable burden'' in overcoming a ''presumption of regularity'' afforded ''the EPA's choice of analytical methodology'') (citing *BCCA Appeal Grp.* v. *EPA,* 355 F.3d 817, 832 (5th Cir. 2003)).

Furthermore, it is not appropriate to compare the bias/error involved in the estimation of total ozone to the potential error in the estimation of the subset of ozone that is contributed by a single state.[305] For example, on a specific day

and the real world. That possibility is inherent in the enterprise of prediction.'').

[304] Nor in the course of this evaluation has the EPA uniformly ruled out the concepts in Attachment A. For example, we noted at proposal that California's identification of a flexibility in Attachment A related to excluding certain air quality data associated with atypical events may be generally consistent with the EPA's modeling guidance, but this does not affect the ultimate determination that California's SIP is not approvable. *See* 87 FR 31454.

[305] See, *e.g.,* 87 FR 9798 at 9816.

the modeled versus monitored ozone value may differ by 2 ppb but that is a relatively small percentage of the total modeled ozone, which for a receptor of interest would be on the order of 70 ppb. It would be unrealistic to assign all of the 2 ppb discrepancy in the earlier example to the estimated impact from a single state because the 2 ppb error would be the combination of the error from all sources of ozone that contribute to the total, including estimated impacts from other states, the home state of the receptor, and natural background emissions.

To address comments that compare the 0.70 ppb threshold to the Federal reference monitors for ozone and the rounding requirements found in 40 CFR part 50, appendix U, the EPA notes that the comment is mistaken in applying criteria related to the precision of monitoring data to the modeling methodology by which we project contributions when quantifying and evaluating interstate transport at Step 2. Indeed, contributions by source or state cannot be derived from the total ambient concentration of ozone at a monitor at all but must be apportioned through modeling. Under our longstanding methodology for doing so, the contribution values identified from upwind states are based on a robust assessment of the average impact of each upwind state's ozone-precursor emissions over a range of scenarios, as explained in the Final Action AQM TSD. This analysis is in no way connected with or dependent on monitoring instruments' precision of measurement. *See EME Homer City II,* 795 F.3d 118, 135–36 ('''[A] model is meant to simplify reality in order to make it tractable.''').

5. Step 2: Justification of a 1 Percent of the NAAQS Contribution Threshold

Comment: Comments contend that the EPA has not provided enough basis for reliance on the 0.70 ppb threshold, claiming that its use is therefore arbitrary and capricious.

EPA Response: The EPA is finalizing its proposed approach of consistently using a 1 percent of the NAAQS contribution threshold at Step 2. This approach ensures both national consistency across all states and consistency and continuity with our prior interstate transport actions for other NAAQS. Comments have not established that this approach is either unlawful or arbitrary and capricious.

The 1 percent threshold is consistent with the Step 2 approach that the EPA applied in CSAPR for the 1997 ozone NAAQS, which has subsequently been applied in the CSAPR Update and revised CSAPR Update when evaluating interstate transport obligations for the 2008 ozone NAAQS. The EPA continues to find 1 percent to be an appropriate threshold. For ozone, as the EPA found in the CAIR, CSAPR, and CSAPR Update, a portion of the nonattainment and maintenance problems in the U.S. results from the combined impact of relatively small contributions from many upwind states, along with contributions from in-state sources and other sources. The EPA's analysis shows that much of the ozone transport problem being analyzed for purposes of evaluating 2015 ozone NAAQS SIP obligations is still the result of the collective impacts of contributions from many upwind states. Therefore, application of a consistent contribution threshold is necessary to identify those upwind states that should have responsibility for addressing their contribution to the downwind nonattainment and maintenance problems to which they collectively contribute. Where a great number of geographically dispersed emissions sources contribute to a downwind air quality problem, which is the case for ozone, EPA believes that, in the context of CAA section 110(a)(2)(D)(i)(I), a state-level threshold of 1 percent of the NAAQS is a reasonably small enough value to identify only the greater-than-de minimis contributers yet is not so large that it unfairly focuses attention for further action only on the largest single or few upwind contributers. Continuing to use 1 percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows the EPA (and states) to apply a consistent framework to evaluate interstate emissions transport under the interstate transport provision from one NAAQS to the next. *See* 81 FR 74504, 74518. *See also* 86 FR 23054, 23085 (reviewing and explaining rationale from CSAPR, 76 FR 48208, 48236–38, for selection of 1 percent threshold).

Further, the EPA notes that the role of the Step 2 threshold is limited and just one step in the 4-Step interstate transport framework. It serves to screen in states for further evaluation of emissions control opportunities applying a multifactor analysis at Step 3. Thus, as the Supreme Court has recognized, the contribution threshold essentially functions to exclude states with ''de minimis'' impacts. *EME Homer City,* 572 U.S. at 500.

Comment: Commenters contend that the EPA cannot use the 1 percent threshold as a determination for significance.

EPA Response: To clarify, the EPA does not use the 1 percent of the NAAQS threshold as the definition of ''significance.'' Rather, where a state's contribution equals or exceeds the 1 percent of the NAAQS threshold, the EPA expects states to further evaluate their emissions to determine whether their emissions constitute significant contribution or interference with maintenance. The contribution threshold is a screening threshold to identify states which may be ''contributing'' to an out of state receptor. The EPA has maintained this interpretation of the relevant statutory language across many rulemakings, though commenters continue to confuse the Step 2 threshold with a determination of ''significance,'' which it is not. *See EME Homer City,* 572 U.S. at 500–502 (explaining the difference between the ''screening'' analysis at Steps 1 and 2 whereby the EPA ''excluded as de minimis any upwind State that contributed less than one percent of the . . . NAAQS'' and the ''control'' analysis at Step 3 whereby the EPA determined ''cost thresholds'' to define significance).

Further, the EPA's air quality and contribution modeling for ozone transport is based on application of the model in a relative sense rather than relying upon absolute model predictions. All models have limitations resulting from uncertainties in inputs and scientific formulation. To minimize the effects of these uncertainties, the modeling is anchored to base period measured data in the EPA's guidance approach for projecting design values. Notably, the EPA also uses our source apportionment modeling in a relative sense when calculating the average contribution metric (used to identify linkages). In this method the magnitude of the contribution metric is tied to the magnitude of the projected average design value which is tied to the base period average measured design value. The EPA's guidance has recommended against applying bright-line criteria for judging whether statistical measures of model performance constitute acceptable or unacceptable model performance.

The Agency continues to find that this method using the CAMx model to evaluate contributions from upwind states to downwind areas is reliable. The agency has used CAMx routinely in previous notice and comment transport rulemakings to evaluate contributions relative to the 1 percent threshold for both ozone and $PM_{2.5}$. In fact, in the original CSAPR, the EPA found that ''[t]here was wide support from commenters for the use of CAMx as an appropriate, state-of-the science air quality tool for use in the [Cross-State Air Pollution] Rule. There were no comments that suggested that the EPA should use an alternative model for quantifying interstate transport.'' 76 FR 48229 (August 8, 2011). In this action, the EPA has taken a number of steps based on comments and new information to ensure to the greatest extent the accuracy and reliability of its modeling projections at Step 1 and 2, as discussed elsewhere in this document.

6. Step 2: Prevention of Significant Deterioration Significant Impact Levels

Comment: Several comments insist that when identifying an appropriate linkage threshold at Step 2 of the 4-step framework, the EPA should consider or rely on the 1 ppb significant impact level (SIL) for ozone used as part of the prevention of significant deterioration PSD permitting process. Comments reference the EPA's April 17, 2018, guidance memorandum, ''Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program'' (SIL guidance), as well as the EPA's March 2018 memorandum's Attachment A flexibilities to lend support to their opinion that the 1 ppb SIL should also be used to determine linkages at Step 2.

EPA Response: The EPA's SIL guidance relates to a different provision of the Clean Air Act regarding implementation of the prevention of significant deterioration (PSD) permitting program. This program applies in areas that have been designated attainment of the NAAQS and is intended to ensure that such areas remain in attainment even if emissions were to increase as a result of new sources or major modifications to existing sources located in those areas. This purpose is different than the purpose of the good neighbor provision, which is to assist downwind areas (in some cases hundreds or thousands of miles away) in resolving ongoing nonattainment of the NAAQS or difficulty maintaining the NAAQS through eliminating the emissions from other states that are significantly contributing to those problems. In addition, as discussed earlier, the purpose of the Step 2 threshold within the EPA's interstate transport framework for ozone is to broadly sweep in all states contributing to identified receptors above a de minimis level in recognition of the collective-contribution problem associated with regional-scale ozone transport. The threshold used in the context of PSD SIL serves an entirely different purpose, and so it does not follow that they should be made equivalent. Further, comments incorrectly associate the EPA's Step 2 contribution threshold with the identification of ''significant'' emissions (which does not occur until Step 3), and so it is not the case that the EPA is interpreting the same term differently.

The EPA has previously explained this distinction between the good neighbor framework and PSD SILs. *See* 70 FR 25162, 25190–25191 (May 12, 2005); 76 FR 48208, 48237 (August 8, 2011). Importantly, the implication of the PSD SIL threshold is not that single-source contribution below this level indicates the absence of a contribution or that no emissions control requirements are warranted. Rather, the PSD SIL threshold addresses whether further, more comprehensive, multi-source review or analysis of air quality impacts are required of the source to support a demonstration that it meets the criteria for a permit. A source with estimated impacts below the PSD SIL may use this to demonstrate that it will not cause or contribute (as those terms are used within the PSD program) to a violation of an ambient air quality standard, but is still subject to meeting applicable control requirements, including best available control technology, designed to moderate the source's impact on air quality.

Moreover, other aspects of the technical methodology in the SIL guidance compared to the good neighbor framework make a direct comparison between these two values misleading. For instance, in PSD permit modeling using a single year of meteorology the maximum single-day 8-hour contribution is evaluated with respect to the SIL. The purpose of the contribution threshold at Step 2 of the 4-step good neighbor framework is to determine whether the average contribution from a collection of sources in a state is small enough not to warrant any additional control for the purpose of mitigating interstate transport, even if that control were highly cost effective. Using a 1 percent of the NAAQS threshold is more appropriate for evaluating multi-day average contributions from upwind states than a 1 ppb threshold applied for a single day, since that lower value of 1 percent of the NAAQS will capture variations in contribution. If EPA were to use a single day reflecting the maximum amount of contribution from an upwind state to determine whether a linkage exists at Step 2, comments' arguments for use of the PSD SIL might have more force. However, that would likely cause more states to become linked, not less. And in any case, consistent with the method in our modeling guidance for projecting future attainment/nonattainment, the good neighbor methodology of using multiple days provides a more robust approach to establishing that a linkage exists at the state level than relying on a single day of data.

7. Step 2: August 2018 Memorandum

Comment: Comments assert that in the August 2018 memorandum the EPA committed itself to approving SIP submissions from states with contributions below 1 ppb, and so now the EPA should or must approve the good neighbor SIP submission from any state with a contribution below 1 ppb, either based on modeling available at the time of the state's SIP submission or at any time.

EPA Response: These comments mischaracterize the content and the EPA's application of August 2018 memorandum. Further, the EPA disputes that the EPA misled states or that the EPA has not appropriately reviewed SIP submissions from states that attempted to rely on an alternative contribution threshold at Step 2.

Specifically, the EPA's August 2018 memorandum provided an analysis regarding ''the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states.'' [306] It interpreted ''that information to make recommendations about what thresholds *may* be appropriate for use in'' SIP submissions (emphasis added).[307] Specifically, the August 2018 memorandum said, ''Because the amount of upwind collective contribution capture with the 1 percent and the 1 ppb thresholds is generally comparable, overall, we believe it *may* be reasonable and appropriate for states to use a 1 ppb contribution threshold, as an alternative to a 1 percent threshold, at Step 2 of the 4-step framework in developing their SIP revisions addressing the good neighbor provision for the 2015 ozone NAAQS.'' (emphasis added).[308] Thus, the text of the August 2018 memorandum does not guarantee that any state with a contribution below 1 ppb has an automatically approvable good neighbor SIP. In fact, the August 2018 memorandum indicated that ''[f]ollowing these recommendations does not ensure that EPA will approve a SIP revision in all instances where the recommendations are followed, as the guidance may not apply to the facts and circumstances underlying a particular SIP. Final decisions by the EPA to approve a particular SIP revision will

[306] August 2018 memorandum, page 1.

[307] August 2018 memorandum, page 1.

[308] August 2018 memorandum, page 4.

only be made based on the requirements of the statute and will only be made following an air agency's final submission of the SIP revision to the EPA, and after appropriate notice and opportunity for public review and comment.'' [309] The August 2018 memorandum also stated, ''EPA and air agencies should consider whether the recommendations in this guidance are appropriate for each situation.'' [310] The EPA's assessment of every SIP submission that invoked the August 2018 memorandum considered the particular arguments raised by the state.[311]

Comment: Some comments allege that the EPA representatives led the states to believe that their SIP submission would be approved on the basis of a 1 ppb contribution threshold. The comments further claim that the EPA has now since reversed course on its August 2018 memorandum and imposed new requirements on states that were not included in the EPA's guidance. One comment suggested EPA switched position without explanation from the August 2018 guidance to its proposed disapprovals, which it viewed as unlawful under *FCC* v. *Fox TV Stations, Inc.,* 556 U.S. 502 (2009).

EPA Response: As an initial matter, we note that the salience of these comments is limited to only a handful of states. The August 2018 memorandum made clear that the Agency had substantial doubts that any threshold greater than 1 ppb (such as 2 ppb) would be acceptable, and the Agency is affirming that a threshold higher than 1 ppb would not be justified under any circumstance for purposes of this action. No comment provided a credible basis for using a threshold even higher than 1 ppb. So this issue is primarily limited to the difference between a 0.70 ppb threshold and a 1.0 ppb threshold. Therefore, we note that this issue is only relevant to a small number of states whose only contributions to any receptor are above 1 percent of the NAAQS but lower than 1 ppb. Under the 2016v3 modeling of 2023 being used in this final action, those states with contributions that fall between 0.70 ppb and 1 ppb included in this action are Alabama, Kentucky, and Minnesota.

The EPA disagrees with comments' claims that the Agency has reversed course on applying the August 2018 memorandum. In line with the memorandum, the EPA evaluated every justification put forward by every state covered by this SIP disapproval action that attempted to justify an alternative threshold under the August 2018 memorandum, which are Alabama,[312] Arkansas,[313] Illinois,[314] Indiana,[315] Kentucky,[316] Louisiana,[317] Michigan,[318] Mississippi,[319] Missouri,[320] and Oklahoma,[321] and Utah.[322] The EPA also addressed criticisms of the 1 percent of the NAAQS contribution threshold made by Ohio [323] and Nevada.[324] (The topic of the EPA's input during state's SIP-development processes is further discussed in the RTC document.)

For this reason, the EPA disagrees with comment that case law reviewing changes in agency positions as articulated in *FCC* v. *Fox TV Stations, Inc.,* is applicable to this action. The Agency has not imposed a requirement that states must use a 1 percent of the NAAQS threshold (which would reflect a change in position from the August 2018 memorandum). Rather, under the terms of the August 2018 memorandum, the Agency has found that Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Michigan, Mississippi, Missouri, Nevada, Ohio, Oklahoma, and Utah have not made a sufficient showing that the use of an alternative contribution threshold is justified for those States. Even if it were found that the Agency's position had fundamentally changed between this rulemaking action and the August 2018 memorandum (which we do not concede to be the case), we do not believe that any state had a legitimate reliance interest that would be sufficient to overcome the countervailing public interest that is served in declining to approve a state's use of the 1 ppb threshold where the state did not have adequate technical justification. First, neither states nor the emissions sources located in those states have incurred any compliance costs based on the August 2018 memorandum. Second, it is not clear that any states invested much of their own public resources in developing state-specific arguments in support of a 1 ppb threshold. As the EPA observed at proposal, in nearly all submittals, the states did not provide the EPA with analysis specific to their state or the receptors to which its emissions are potentially linked. In one case, the EPA's proposed approval of Iowa's SIP submittal, ''*the EPA expended its own resources to attempt to supplement the information submitted by the state,* in order to more thoroughly evaluate the state-specific circumstances that could support approval.'' E.g., 87 FR 9806–07 (emphasis added). The EPA emphasizes again that it was the EPA's sole discretion to perform this analysis in support of the state's submittal, and the Agency is not obligated to conduct supplemental analysis to fill the gaps whenever it believes a state's analysis is insufficient. *Id.*

We acknowledge that certain states may have assumed the EPA would approve SIP submissions from states whose contribution to any receptor was below 1 ppb, but that assumption reflected a misunderstanding of the August 2018 memorandum, and in any case, an assumption is not, as a legal matter, the same thing as a reliance interest.

The EPA is not formally rescinding the August 2018 memorandum in this action or at this time, but since guidance memoranda are not binding in the first place, it is not required that agencies must ''rescind'' a guidance the moment it becomes outdated or called into question. As the Agency made clear in the August 2018 memorandum, all of EPA's proposals for action on interstate transport SIP submissions are subject to rulemaking procedure, including public notice and comment, before the EPA makes a final decision.

Although the EPA is not formally revoking the August 2018 memorandum at this time, and we have separately found that no state successfully established a basis for use of a 1 ppb threshold, we also continue to believe, as set forth in our proposed disapprovals, that national ozone transport policy associated with addressing obligations for the 2015 ozone NAAQS is not well-served by allowing for less protective thresholds at Step 2. Furthermore, the EPA disagrees that national consistency is an inappropriate consideration in the context of interstate ozone transport. The Good Neighbor provision, CAA section 110(a)(2)(D)(i)(I), requires to a unique degree of concern for consistency, parity, and equity across

[309] August 2018 memorandum, page 1.

[310] August 2018 memorandum, page 1.

[311] 87 FR 64423–64424 (Alabama); 87 FR 9806–9807 (Arkansas); 87 FR 9852–9853 (Illinois); 87 FR 9855–9856 (Indiana); 87 FR 9508–9511 (Kentucky); 87 FR 9812–9813 (Louisiana); 87 FR 9861–9862 (Michigan); 87 FR 9557 (Mississippi); 87 FR 9541–9543 (Missouri); 87 FR 31492 (Nevada); 87 FR 9870–9871 (Ohio); 87 FR 9818–9820 (Oklahoma); 87 FR 31477–31451 (Utah).

[312] 87 FR 64423–64424.

[313] 87 FR 9806–9807.

[314] 87 FR 9852–9853.

[315] 87 FR 9855–9856.

[316] 87 FR 9508–9511.

[317] 87 FR 9812–9813.

[318] 87 FR 9861–9862.

[319] 87 FR 9557.

[320] 87 FR 9541–9543.

[321] 87 FR 9818–9820.

[322] 87 FR 31477–31451.

[323] 87 FR 9870–9871.

[324] 87 FR 31492.

state lines.[325] For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. Based on the EPA's review of good neighbor SIP submissions to-date and after further consideration of the policy implications of attempting to recognize an alternative Step 2 threshold for certain states, the Agency now believes the attempted use of different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns. The availability of different thresholds at Step 2 has the potential to result in inconsistent application of good neighbor obligations based solely on the strength of a state's SIP submission at Step 2 of the 4-step interstate transport framework. From the perspective of ensuring effective regional implementation of good neighbor obligations, the more important analysis is the evaluation of the emissions reductions needed, if any, to address a state's significant contribution after consideration of a multifactor analysis at Step 3, including a detailed evaluation that considers air quality factors and cost. While alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of an alternative threshold would allow certain states to avoid further evaluation of potential emissions controls while other states with a similar level of contribution would proceed to a Step 3 analysis. This can create significant equity and consistency problems among states.

One comment suggested that the EPA could address this potentially inequitable outcome by simply adopting a 1 ppb contribution threshold for all states. However, the August 2018 memorandum did not conclude that 1 ppb would be appropriate for all states, and the EPA does not view that conclusion to be supported at present. The EPA recognized in the August 2018 memorandum that on a nationwide basis there was some similarity in the amount of total upwind contribution captured between 1 percent and 1 ppb. However, while this may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold for every state. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3 (*e.g.,* roughly 7 percent of total upwind state contribution was lost according to the modeling underlying the August 2018 memorandum; in the EPA's 2016v2 and 2016v3 modeling, the amount lost is 5 percent). Further, this logic has no end point. A similar observation could be made with respect to any incremental change. For example, should the EPA next recognize a 1.2 ppb threshold because that would only cause some small additional loss in capture of upwind state contribution as compared to 1 ppb? If the only basis for moving to a 1 ppb threshold is that it captures a ''similar'' (but actually smaller) amount of upwind contribution, then there is no basis for moving to that threshold at all. Considering the core statutory objective of ensuring elimination of all significant contribution to nonattainment or interference with maintenance of the NAAQS in other states as well as the broad, regional nature of the collective contribution problem with respect to ozone, we continue to find no compelling policy reason to adopt a new threshold for all states of 1 ppb.

It also is unclear why use of a 1 ppb threshold would be appropriate for all states under a more protective NAAQS when a 1 percent of the NAAQS contribution threshold has been used for less protective NAAQS. To illustrate, a state contributing greater than 0.75 ppb but less than 1 ppb to a receptor under the 2008 ozone NAAQS was ''linked'' at Step 2 using the 1 percent of the NAAQS contribution threshold, but if a 1 ppb threshold were used for the 2015 ozone NAAQS, then that same state would not be ''linked'' to a receptor at Step 2 under a NAAQS that is set to be more protective of human health and the environment. Consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which used a Step 2 threshold of 1 percent of the NAAQS for two less protective ozone NAAQS), is an important consideration. Continuing to use a 1 percent of NAAQS approach ensures that if the NAAQS are revised and made more protective, an appropriate increase in stringency at Step 2 occurs, to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport obligations. *See* 76 FR 48208, 48237–38.

One comment identified that if the EPA were to use a 1 percent of the NAAQS contribution threshold, the EPA would be obligated to seek feedback on that contribution threshold through a public notice and comment process. The EPA's basis and rationale for every SIP submission covered by this final SIP disapproval action, including the use of a 1 percent of the NAAQS contribution threshold, was in fact presented for public comment. The EPA received, and is addressing in this action, many detailed comments about contribution thresholds. Further, the EPA's application of a 1 percent of the NAAQS threshold has been consistently used in notice-and-comment rulemakings beginning with the CSAPR rulemaking in 2010–2011 and including both FIP actions (CSAPR Update and Revised CSAPR Update) and numerous actions on ozone transport SIP submissions. In each case, the 1 percent of the NAAQS threshold was subject to rigorous vetting through public comment and the Agency's response to those comments, including through analytical evaluations of alternative thresholds. *See, e.g.,* 81 FR 74518–19. By contrast, the August 2018 memorandum was not issued through notice-and-comment rulemaking procedures, and the EPA was careful to caveat its utility and ultimate reliability for that reason.

Comment: Some comments claim that the EPA is applying the August 2018 memorandum inconsistently based on the EPA's actions with regard to action good neighbor SIP submissions from Iowa and Oregon for the 2015 ozone NAAQS and Arizona's good neighbor SIP submission for the 2008 ozone NAAQS.

EPA Response: The EPA disagrees that there is any such inconsistency. The EPA withdrew a previously proposed approval of Iowa's SIP submission where the Agency had attempted to substantiate the use of a 1 ppb contribution threshold, and re-proposed and finalized approval of that SIP based on a different rationale using a 1 percent of the NAAQS contribution threshold. 87 FR 9477 (Feb. 22, 2022); 87 FR 22463 (April 15, 2022). As explained earlier in this section, this experience of the EPA attempting to justify 1 ppb for a state through additional air quality analysis, where the state had not conducted an analysis the Agency considered to be sufficient is part of the reason the Agency is moving away from attempting to justify use of this alternative contribution threshold.

The EPA also disputes the claim that Oregon and Arizona were the only states ''allowed'' to use a 1 ppb threshold. The EPA approved Oregon's SIP submission for the 2015 ozone NAAQS on May 17,

[325] The EPA notes that Congress has placed on the EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

2019, and both Oregon and the EPA relied on a 1 percent of the NAAQS contribution threshold. 84 FR 7854, 7856 (March 5, 2019) (proposal); 84 FR 22376 (May 17, 2019) (final). In our FIP proposal for the 2015 ozone NAAQS, the EPA explained it was not proposing to conduct an error correction for Oregon even though updated modeling indicated Oregon contributed above 1 percent of the NAAQS to monitors in California, because the specific monitors in California are not interstate ozone transport ''receptors'' at Step 1. *See* 87 FR 20036, 20074–20075 (April 6, 2022). The EPA solicited public comment on its approach to Oregon's contribution to California receptors as part of the 2015 ozone NAAQS transport FIP development, and the Agency has not yet taken final action on that FIP. In 2016, the EPA previously approved Arizona's good neighbor SIP for the earlier 2008 ozone NAAQS based on a similar rationale with regard to certain monitors in California in 2016. 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule). The Agency's view with respect to its evaluation of both Arizona and Oregon is that specific monitors in California are not interstate ozone transport ''receptors'' at Step 1. The EPA has not approved or applied an alternative Step 2 threshold for any state.

Comments related to the specific circumstances of an individual state and/or its arguments put forth in its SIP submission as it pertains to the August 2018 Memorandum are further addressed in the RTC document.

8. Step 3: States' Step 3 Analyses for the 2015 Ozone NAAQS

Comment: Comments state that the EPA has not provided any guidance on what an appropriate Step 3 analysis would entail, and therefore any decision where the Agency rejects a Step 3 analysis is arbitrary and capricious. One comment claims that not a single state has successfully made a Step 3 demonstration leading to an approvable interstate transport SIP for the 2015 ozone NAAQS. Comments note that there is no requirement in the CAA that states must complete an analysis similar to the EPA's, and the EPA cannot substitute its own judgment for that of the state's in crafting a SIP. Rather, the EPA is obligated to defer to state choices. One comment asserts that the EPA is required to interpret the term ''significant contribution'' in a manner ''which ties contribution to an amount which contributes significantly to downwind maintenance or nonattainment problems.'' Another comment claims the EPA is intentionally exploiting the Supreme Court decision in *EME Homer City* to justify any requirements it deems necessary to further Federal policy decisions. Some comments identify that some states did not conduct a Step 3 analysis in their submitted SIPs because, using the flexibilities provided in the 2018 memoranda, these states concluded in Step 1 and Step 2 that no controls were required. One comment suggests that the EPA propose an 18-month period to allow these states to proceed with Steps 3 and 4.

EPA Response: The EPA disagrees that it is obligated to defer to states' choices in the development of good neighbor SIP submissions. As required by the Act, the EPA has evaluated each of the SIP submissions for compliance with the CAA, including whether an adequate Step 3 analysis was conducted—or whether states had offered an approvable alternative approach to evaluating their good neighbor obligations—and found in each case that what these states submitted was not approvable. The Supreme Court has recognized that the EPA is not obligated to provide states with guidance before taking action to disapprove a SIP submission. *EME Homer City,* 572 U.S. at 508–10. Nonetheless, throughout the entire history of the EPA's actions to implement the good neighbor provision for ozone, starting with the 1998 NO_X SIP Call, we have consistently adopted a similar approach at Step 3 that evaluates emissions reduction opportunities for linked states applying a multifactor analysis. States could have performed a similar analysis of emissions control opportunities. The EPA has not directed states that they must conduct a Step 3 analysis in precisely the manner the EPA has done in its prior regional transport rulemakings; however, SIPs addressing the obligations in CAA section 110(a)(2)(D)(i)(I) must prohibit ''any source or other type of emissions activity within the State'' from emitting air pollutants which will contribute significantly to downwind air quality problems. Thus, States seeking to rely on an alternative approach to defining ''significance'' must use an approach that comports with the statute's objectives to determine whether and to what degree emissions from a state should be ''prohibited'' to eliminate emissions that will ''contribute significantly to nonattainment in, or interfere with maintenance of'' the NAAQS in any other state. Further, the approach selected must be reasonable and technically justified. Therefore, while the EPA does not direct states to use a particular framework, nonetheless, each state must show that its decision-making was based on a ''technically appropriate or justifiable'' evaluation.

Further, the Agency has a statutory obligation to review and approve or disapprove SIP submittals according to the requirements of the Clean Air Act. *See* CAA section 110(k)(3). And the Agency is empowered to interpret those statutory requirements and exercise both technical and policy judgment in acting on SIP submissions. Indeed, the task of allocating responsibility for interstate pollution particularly necessitates Federal involvement. *See EME Homer City,* 572 U.S. at 514 (''The statute . . . calls upon the Agency to address a thorny causation problem: How should EPA allocate among multiple contributing upwind States responsibility for a downwind State's excess pollution?''); *see also Wisconsin,* 938 F.3d at 320. Further, we have consistently disapproved states' good neighbor SIP submissions addressing prior ozone NAAQS when we have found those states linked through our air quality modeling and yet the state failed to conduct an analysis of emissions control opportunities, or such analysis was perfunctory or otherwise unsatisfactory. We have been upheld in our judgment that such SIPs are not approvable. *See Westar Energy* v. *EPA,* 608 Fed. App'x 1, 3 (DC Cir. 2015) (''EPA acted *well within the bounds* of its delegated authority when it disapproved of Kansas's proposed SIP.'') (emphasis added).

With respect to the assertion that no state has successfully avoided a FIP with an approvable Step 3 analysis, we note first that at this time, no final FIP addressing the 2015 ozone NAAQS has been promulgated. More directly to the point, no state submission that is the subject of this disapproval action offered any additional emissions control measures. While it is conceivable that a Step 3 analysis may result in a determination that no additional controls are needed, EPA expects that such circumstances will generally be rare, else the CAA's interstate transport provisions are rendered ineffective. For example, the EPA determined in the CSAPR Update that even though the District of Columbia and Delaware were linked to out of state receptors at Steps 1 and 2 of the 4-step interstate transport framework, no additional control measures were required of either jurisdiction. As to the District of Columbia, we found that there were no affected EGU sources that would fall under the CSAPR Update's control program. For Delaware, we found that there were no emissions reductions available from any affected sources for any of the emissions control stringencies that were analyzed. *See* 81 FR 74504, 74553. No state's submission covered in this action contained an emissions control analysis that would allow for these types of conclusions to be reached for all of its sources.[326] States generally did not conduct any comparative analysis of available emissions control strategies—nor did they prohibit any additional ozone-precursor emissions.

We are unclear what another comment intends in asserting that the EPA is required to interpret ''significant contribution'' in a manner ''which ties contribution to an amount which contributes significantly to downwind maintenance or nonattainment problems.'' The EPA disagrees that: (1) It has imposed or mandated a specific approach to Step 3 in this action, (2) this action established a particular level of emissions reduction that states were required to achieve, or (3) it mandated a particular methodology for making such a determination. To the extent the comment suggests that the Agency cannot mandate that states use cost as a method of allocating responsibility in their transport SIPs, first, the Agency has not done so. Further, as to whether cost could be used as a permissible method of allocating responsibility, the comment ignores the Supreme Court's holding to the contrary in *EME Homer City,* 572 U.S. at 518, and the D.C. Circuit's earlier holding to the same effect in *Michigan,* 213 F.3d at 687–88, both of which upheld the EPA's approach of using uniform cost-effectiveness thresholds to allocate upwind state responsibilities under the good neighbor provision for prior NAAQS. While this approach may be reasonable to apply again for the 2015 ozone NAAQS (and the EPA has proposed to do so in the proposed FIP action published on April 6, 2022), the EPA did not impose such a requirement on states in developing SIP submissions, nor is the EPA finding any SIP submission not approvable based on a failure to use this particular methodology.

In its March 2018 memorandum, Attachment A, the Agency acknowledged that there could be multiple ways of conducting a Step 3 analysis. The Agency did not endorse any particular approach and noted the Attachment was merely a list of stakeholder ideas that the EPA was not recommending any state follow. The apparent result of this ''flexibility,'' however, was that no state presented a Step 3 analysis that resulted in including any enforceable emissions reductions to address good neighbor obligations for the 2015 ozone NAAQS in their interstate transport SIP submittals. Likewise, the comment here did not include information or analysis establishing that any particular alternative Step 3 approach should have been approved or that any state performed such an analysis in a manner that would have addressed ''significant contribution'' even in the manner the comment appears to be suggesting.

Notably, materials appended to one State's SIP submission, developed by the Midwest Ozone Group (MOG), did present an analysis applying an approach to ''significant contribution'' that was based on calculating a proportional share of each state's contribution to a downwind receptor, and this methodology would have imposed on that State's, Kentucky's, sources an obligation to eliminate 0.02 ppb of ozone at the relevant receptor. *See* 87 FR 9507. While the EPA does not endorse or here evaluate the merits of such an approach, it is noteworthy that the State in that instance did not adopt that approach, did not impose that obligation on its sources through enforceable measures by revising its SIP, and offered no explanation for its decision not to do so. *See id.* 9516 (''This approach would have imposed additional emissions reductions for Kentucky sources. Kentucky's final SIP did not consider MOG's proposal and did not provide an explanation for why it was rejecting this approach to allocating upwind emissions reductions, even though it appended this recommendation to its SIP submittal.'').

9. Step 4: Attempt To Rely on FIPs in a SIP Submission

Comment: One comment states that FIPs or other Federal emissions control measures do not have to be incorporated into and enforceable under state law to be an approvable SIP measure. They view it as acceptable for a state to rely in its SIP Submission on the emissions reductions achieved by prior ozone transport FIPs, such as the CSAPR Update or the Revised CSAPR Update, as a permissible means of achieving emissions reductions to eliminate significant contribution for the 2015 ozone NAAQS.

EPA Response: The EPA disagrees. As the EPA has noted on page 16 of our September 2013 memorandum ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act sections 110(a)(1) and 110(a)(2)'' (2013 Infrastructure SIP Guidance): ''a FIP is not a state plan and thus cannot serve to satisfy the state's obligation to submit a SIP.'' [327] Indeed, the general principle that measures relied on to meet states' CAA obligations must be part of the SIP has been recognized by courts, such as in *Committee for a Better Arvin,* 786 F.3d 1169 (9th Cir. 2015).

This principle is grounded in the recognition that if such measures are not rendered enforceable within the SIP itself, then they may be modified or amended in ways that would undermine the basis for the state's reliance on them, while the approved SIP itself would purport to have addressed the relevant obligation merely by outdated reference to that modified or nonexistent control measure residing outside the SIP. For example, to be credited for attainment demonstration purposes, requirements that may otherwise be federally enforceable (such as new source review permit limits or terms in federally enforceable consent orders), must be in the state's implementation plan so that they could not later be changed without being subject to the EPA's approval. This principle is instrumental to ensuring that states cannot take credit for control measures that might be changed (even by the EPA itself) without the EPA's required approval action under CAA section 110, which includes the obligation to ensure there is no interference or backsliding with respect to all applicable CAA requirements. *See* CAA section 110(l). *See also Montana Sulfur and Chemical Co.* v. *EPA,* 666 F.3d 1174, 1195–96 (9th Cir. 2012) (''The EPA correctly reads 42 U.S.C. 7410(a)(2) as requiring states to include enforceable emissions limits and other control measures *in the plan itself.*'') (emphasis in original); 40 CFR 51.112(a) (''Each plan must demonstrate that the measures, rules, and regulations *contained in it* are adequate to provide for the timely attainment and

[326] We note that California's SIP submission is not approvable at Step 3, despite the fact that the EPA has not identified NO_X emissions control opportunities at the state's EGUs. Nonetheless, the SIP submission is not approvable because the state attempted to rely on the CSAPR Update cost threshold to justify a no-control determination when that threshold was in relation to a partial remedy for a less protective NAAQS, and even if it could be reasonably concluded that no emissions reductions are appropriate at EGUs in California, the SIP submission did not conduct an adequate analysis of emissions control opportunities at its non-EGU industrial sources. *See* 87 FR 31459–60.

[327] Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2), September 13, 2013 (available at *https://www.epa.gov/sites/default/files/2015-12/documents/guidance_on_infrastructure_sip_elements_multipollutant_final_sept_2013.pdf*).

maintenance of the national standard that it implements.'') (emphasis added).

The EPA has applied this same interpretation in implementing other infrastructure SIP requirements found in CAA section 110(a)(2). For example, in implementing CAA section 110(a)(2)(C), (D)(i)(II), (D)(ii), and (J) relating to the permitting program for PSD, the EPA has developed FIPs that incorporate by reference provisions codified at 40 CFR 51.21, and some states have taken delegation of that FIP to implement the relevant requirements. But the EPA does not and cannot approve the state as having met these infrastructure SIP elements, even by virtue of taking delegation of the FIP. *See, e.g.,* 83 FR 8818, 8820 (March 1, 2018). Likewise, under one of the pathways presented in our 2013 Infrastructure SIP Guidance, the EPA does not approve SIPs addressing interstate visibility transport obligations under CAA section 110(a)(2)(D)(i)(II) (''prong 4'') until the state itself has a fully approved regional haze plan, and states cannot rely on the CSAPR ''better than BART'' FIPs to meet their prong 4 requirements until they have replaced that FIP with an approved SIP. *See, e.g.,* 84 FR 13800, 13801 (April 8, 2019); 84 FR 43741, 43744 (Aug. 22, 2019).

The comment does not provide contrary examples where the EPA has approved, as a SIP-based emissions control program, requirements that are established through Federal regulation or other types of emissions control programs that are outside the SIP. It is true that in the first two steps of the 4-step interstate transport framework, the EPA conducts air quality modeling based on emissions inventories reflective of on-the-books state and Federal emissions control requirements, to make determinations about air quality conditions and contribution levels that can be anticipated *in the baseline* in a future analytic year. If the comment's examples were intended to reference this consideration of Federal measures in prior actions on SIP submittals, the EPA agrees that it does consider such measures at these steps of its analysis, and the EPA has consistently taken this approach throughout its prior ozone transport actions. But here we are discussing Step 3 and 4 of the framework, where states that have been found to contribute to downwind nonattainment and maintenance problems, *e.g.,* are linked at Steps 1 and 2 to an out of state receptor, would need to evaluate their continuing emissions to determine what if any of those emissions should be deemed ''significant'' (*e.g.,* Step 3) and eliminated through enforceable emissions control requirements (*e.g.,* Step 4). The EPA is not aware of any good neighbor SIP submission that it has approved where a state purported to eliminate its significant contribution (*e.g.,* satisfy Steps 3 and 4) simply by referring to Federal measures that were not included in its SIP and enforceable as a matter of state law. Finally, it bears emphasizing that the EPA's assessment of the 2015 ozone transport SIPs has already accounted for the emissions-reducing effects of both the CSAPR Update and the Revised CSAPR Update in its baseline air quality modeling at Steps 1 and 2, and so pointing to either of those rules as measures that would eliminate significant contribution at Step 3, for purposes of the 2015 ozone NAAQS, would be impermissible double-counting.

C. Good Neighbor Provision Policy

1. Mobile Source Emissions

Comment: Several comments assert that mobile source emissions within the home state of the location of receptors are the primary source of nonattainment problems in downwind areas. Some comments additionally state that a larger portion of their own upwind state emissions is from mobile source emissions. These comments request that the EPA focus on these emissions sources rather than stationary sources to reduce ongoing nonattainment problems. These comments claim mobile sources are federally regulated and, therefore, the EPA bears the responsibility to either take action to reduce mobile source emissions nationwide or encourage downwind states to implement strategies to reduce their own local mobile source emissions.

Response: The EPA recognizes that nationwide, mobile sources represent a large portion of ozone-precursor emissions and, as such, would be expected to have a large impact on nonattainment and maintenance receptors.

The EPA has been regulating mobile source emissions since it was established as a Federal agency in 1970 and is committed to continuing the effective implementation and enforcement of current mobile source emissions standards and evaluating the need for additional standards.[328] The EPA believes that the NO_X reductions from its Federal programs are an important reason for the historical and long-running trend of improving air quality in the United States. The trend helps explain why the overall number of receptors and severity of ozone nonattainment problems under the 1997 and 2008 ozone NAAQS have declined. As a result of this long history, NO_X emissions from onroad and nonroad mobile sources have substantially decreased and are predicted to continue to decrease into the future as newer vehicles and engines that are subject to the more recent and more stringent standards replace older vehicles and engines.[329]

The EPA included mobile source emissions in the 2016v2 modeling used to support the proposal of these SIP disapproval actions to help determine state linkages at Steps 1 and 2 of the 4-step interstate transport framework and has done likewise in its 2016v3 modeling. However, whether mobile source emissions are a large portion of an upwind or downwind state's NO_X emissions, and whether they represent a large portion of the contribution to downwind nonattainment and maintenance receptors, does not answer the question regarding the adequacy of an upwind state's SIP submission. The question is whether ''any source or other type of emissions activity'' (in the collective) in an upwind state is contributing significantly to downwind receptors, *see* CAA section 110(a)(2)(D)(i). A state's transport SIP must include a technical and adequate justification to support its conclusion that the state has satisfied its interstate transport obligations for the 2015 ozone NAAQS.

To the extent that comments argue that mobile source emissions should be the focus of emissions reductions for the purposes of resolving interstate transport obligations, states could have provided such an analysis for how mobile source reductions might achieve necessary reductions. *See, e.g.,* 70 FR 25209. However, states conducted no such analysis of methods or control techniques that could be used to reduce mobile source emissions, instead claiming that states cannot control mobile source emissions, as this is a federally-regulated sector, or states cannot reasonably control these emissions. States do have options, however, to reduce emissions from certain aspects of their mobile source

[328] On December 20, 2022, the EPA finalized more stringent emissions standards for NO_X and other pollutants from heavy-duty vehicles and engines, beginning with model year 2027. *See https://www.epa.gov/regulations-emissions-vehicles-and-engines/final-rule-and-related-materials-control-air-pollution.* The EPA is also developing new multi-pollutant standards for light- and medium-duty vehicles as well as options to address pollution from locomotives.

[329] *https://gispub.epa.gov/air/trendsreport/2022/#home.*

sectors, and to the extent a state is attributing its contribution to out of state receptors to its mobile sources, it could have conducted an analysis of possible programs or measures that could achieve emissions reductions from those sources. (For example, a general list of types of transportation control measures can be found in CAA section 108(f).[330])

State-specific issues raised by comments are further addressed in the RTC document.

2. International Contributions

Comment: Several comments state that international emissions contribute to nonattainment and maintenance receptors downwind, and these emissions are not within the jurisdiction of the states. They advocate for the EPA should considering this when acting on SIP submissions. Some comments claim that, in the west, international contributions are even greater than in eastern portions of the U.S. and support their notion that the EPA's evaluation of interstate transport should take special consideration of unique regional factors when determining upwind state obligations, or that the Agency should otherwise explain why it is still inappropriate to factor in higher international contributions, as the Agency has done in Oregon's case.

Response: The EPA responded to similar arguments related to international emissions included in the SIP submissions of Arkansas, California, Illinois, Indiana, Kentucky, Michigan, Missouri, Ohio, Utah, Wyoming, and West Virginia in the proposed disapprovals.[331] No comments on the proposed disapprovals provided new information to indicate the EPA's initial assessment was incorrect. These comments' reasoning related to international emissions is inapplicable to the requirements of CAA section 110(a)(2)(D)(i)(I). The good neighbor provision requires states and the EPA to address interstate transport of air pollution that significantly contributes to downwind states' ability to attain and maintain the NAAQS. Whether emissions from other states or other countries also contribute to the same downwind air quality issue is typically not relevant in assessing whether a downwind state has an air quality problem, or whether an upwind state is significantly contributing to that problem. (Only in rare cases has EPA concluded that certain monitoring sites should not be considered receptors at Step 1 due to the very low collective upwind-state contribution at those receptors. *See* the RTC document.) States are not obligated under CAA section 110(a)(2)(D)(i)(I) to act alone to reduce emissions in amounts sufficient to resolve a downwind receptor's nonattainment or maintenance problem. Rather, states are obligated to eliminate their own ''significant contribution'' to that receptor or ''interference'' with the ability of other states to attain or maintain the NAAQS. The statutory standard is, fundamentally, one of contribution, not causation.

Indeed, the D.C. Circuit in *Wisconsin* specifically rejected petitioner arguments suggesting that upwind states should be excused from good neighbor obligations on the basis that some other source of emissions (whether international or another upwind state) could be considered the ''but-for'' cause of downwind air quality problem. *See Wisconsin,* 938 F.3d at 323–324. The court viewed petitioners' arguments as essentially an argument ''that an upwind state 'contributes significantly' to downwind nonattainment only when its emissions are the sole cause of downwind nonattainment.'' *Id.* at 324. The court explained that ''an upwind state can 'contribute' to downwind nonattainment even if its emissions are not the but-for cause.'' *Id.* at 324–325. *See* also *Catawba County* v. *EPA,* 571 F.3d 20, 39 (DC Cir. 2009) (rejecting the argument ''that 'significantly contribute' unambiguously means 'strictly cause''' because there is ''no reason why the statute precludes EPA from determining that [an] addition of [pollutant] into the atmosphere is significant even though a nearby county's nonattainment problem would still persist in its absence''); *Miss. Comm'n on Envtl. Quality* v. *EPA,* 790 F.3d 138, 163 n.12 (DC Cir. 2015) (observing that the argument that ''there likely would have been no violation at all . . . if it were not for the emissions resulting from [another source]'' is ''merely a rephrasing of the but-for causation rule that we rejected in Catawba County''). Therefore, a state is not excused from eliminating its significant contribution on the basis that international emissions also contribute some amount of pollution to the same receptors to which the state is linked.

To the extent comments compare the influence of international emissions with the EPA's treatment of receptors in California to which Oregon contributes greater than 0.70 ppb, the EPA responds to these comments in the RTC document.

3. Western Interstate Transport Policy

Comment: Several comments argue that the EPA should consider an alternative approach to evaluating interstate transport in the western U.S. Comments assert there are considerations unique to the western states, such as increased background, international, and wildfire contributions to ozone concentrations in the west. Some commenters believe a ''case-by-case'' assessment is more appropriate for evaluating western states' interstate transport obligations, as they claim the EPA had done for the 2008 ozone standards. They additionally argue that the EPA modeling is not able to accurately project ozone concentrations in the west because of these factors, along with the west's unique topographical influence on ozone transport.

Response: The EPA disagrees that either its nationwide photochemical grid modeling or the 4-step interstate transport framework for ozone cannot generally be applied to states in the western region of the U.S. and has maintained that position consistently throughout numerous actions.[332] Though at times the EPA has found it appropriate to examine more closely discreet issues for some western states,[333] the 4-step interstate transport framework itself is appropriate for assessing good neighbor obligations of western states in the absence of those circumstances. The EPA evaluated the contents of the western states' SIP submissions covered by this action on the merits of the information the states provided. As described at proposal and reiterated in Section IV, the EPA is finalizing its disapproval of California,

[330] In making this observation, the EPA is not suggesting that mobile source emissions reductions are necessarily required to address a state's good neighbor obligations, but merely pointing out that if the state itself attributes the problem to mobile sources, then it is reasonable to expect that further analysis of such control strategies would be explored.

[331] 87 FR 9798, 9809–9810 (Feb. 22, 2022) (Arkansas); 87 FR 31443, 31460–31461 (May 24, 2022) (California); 87 FR 9854 (Illinois); 87 FR 9859–9860 (Indiana); 87 FR 9498, 9508 (Feb. 22, 2022) (Kentucky); 87 FR 9838, 9865 (Michigan); 87 FR 9533, 9543 (Feb. 22, 2022) (Missouri); 87 FR 9838 at 9874 (Ohio); 87 FR 31470, 31482 (May 24, 2022) (Utah); 87 FR 9516, 9527 (Feb. 22, 2022) (West Virginia); 87 FR 31495, 31507 (May 24, 2022) (Wyoming).

[332] For a discussion of this history, *see* for example 87 FR 31480–81 (proposed disapproval of Utah SIP submission) and 87 FR 31453–56 (proposed disapproval of California SIP submission).

[333] *See, e.g.,* Approval of Arizona's 2008 ozone NAAQS interstate transport SIP submission, 81 FR 15200 (March 22, 2016) (Step 1 analysis concluding certain monitors in California should not be considered interstate transport receptors for purposes of the good neighbor provision for the 2008 ozone NAAQS); *see also* 87 FR 61249, 61254–55 (Oct. 11, 2022) (in approving Colorado's interstate transport SIP for the 2015 ozone NAAQS, analyzing unique issues associated with wintertime inversion conditions in certain western areas).

Nevada, and Utah's SIP submissions. This final determination is based on these evaluations, as well as the EPA's 2016v2 and 2016v3 modeling following stakeholder feedback.

The EPA continues to find it appropriate to rely on the results of its nationwide modeling in the western U.S., despite comments concerning the ability for the EPA's modeling to accurately project ozone concentrations and contributions in western states, as well as its ability to support the EPA's 4-step framework for assessing interstate transport. The EPA's nationwide photochemical grid modeling considers multiple complex factors, including those raised in comments, such as terrain complexities, variability in emissions (*e.g.,* wildfire emissions), meteorology, and topography. While the EPA continues to believe its 2016v2 modeling performs equally as well in both the west and the east, the EPA has adjusted its 2016v3 modeling to ensure its predictions more closely replicate the relative magnitude of concentrations and day-to-day variability that are characteristic of observed 8-hour daily maximum ozone concentrations in each region, as explained in Section III.A and the RTC document. As such, the EPA continues to find its modeling reliable for characterizing ozone concentrations and contribution values in the western U.S. Further responses regarding the reliability of the EPA's modeling in the western U.S. is provided in the RTC document.

The EPA disagrees with comments noting that the Agency took an alternative approach for western states when assessing interstate transport obligations under the 2008 ozone NAAQS. As explained in our proposed disapproval of California's 2015 ozone NAAQS interstate transport SIP submission, while the EPA has in limited circumstances found unique issues associated with addressing ozone transport in western states, the EPA has consistently applied the 4-step interstate transport framework in western states, as it has done here, and has identified ozone transport problems in the west that are similar to those in the east.[334] [335] At proposal, the EPA addressed states' arguments regarding the impact of unique factors such as topography and, as part of the EPA's evaluation of the contents of the SIP submission, provided explanation as to why the EPA found the states' arguments did not support their conclusions regarding long range transport of ozone in the west.[336]

While comments point to relatively higher level of contributions from non-anthropogenic, local, or international contributions in the west as reason for evaluating interstate transport differently in the west, a state is not excused from eliminating its significant contribution due to contributions from these sources, where the data shows that anthropogenic emissions from upwind states also contribute collectively to identified receptors at levels that indicate there to be an interstate contribution problem as well. As stated in Section V.C.2, a state is not excused from eliminating its significant contribution on the basis that international emissions also contribute some amount of pollution to the same receptors to which the state is linked. This same principle applies broadly to other arguments as to which emissions are the ''cause'' of the problem; the good neighbor provision established a contribution standard, not a but-for causation standard. *See Wisconsin,* 938 F.3d at 323–25.

[334] 87 FR 31443, 31453.

[335] 81 FR 74503, 74523.

[336] *See, e.g.,* 87 FR 31443, 31457. The EPA evaluated California's qualitative consideration of unique topographic factors that may influence the transport of emissions from sources within the state to downwind receptors in Colorado and Arizona. The EPA concluded that the State's arguments do not present sufficient evidence that called into question the results of the EPA's modeling.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Orders 12866: Regulatory Planning and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act. This final action does not establish any new information collection requirement apart from what is already required by law. This finding relates to the requirement in the CAA for states to submit SIPs under CAA section 110(a)(2)(D)(i)(I) addressing interstate transport obligations associated with the 2015 ozone NAAQS.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This action is disapproving SIP submissions for not containing the necessary provisions to satisfy interstate transport requirements under CAA section 110(a)(2)(D)(i)(I).

D. Unfunded Mandates Reform Act of 1995 (UMRA)

This action does not contain any unfunded mandate as described in UMRA 2 U.S.C. 1531–1538 and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the National Government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, this action does not impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. This action includes disapproving the portion of Oklahoma's SIP submission addressing the state's good neighbor obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS and applies to certain areas of Indian country as discussed in Section IV.C of the proposed action, ''Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 Ozone National Ambient Air Quality Standards'' (87 FR 9798 at 9824, February 2, 2022). However, this action does not impose substantial direct compliance costs on federally recognized tribal governments because no actions will be required of tribal governments. This action will also not preempt tribal law as no Oklahoma tribe implements a regulatory program under the CAA, and thus does not have applicable or related tribal laws. The EPA consulted with tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this regulation to permit them to have meaningful and timely input into its development. A summary of that consultation is provided in the file ''2015 Ozone Transport OK Tribal Consultation Meeting Record 3–3–2022,'' in the docket for this action.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive order. This action is not subject to Executive Order 13045 because it merely disapproves SIP submissions as not containing the necessary provisions to satisfy interstate transport requirements under CAA section 110(a)(2)(D)(i)(I).

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 FR 7629, Feb. 16, 1994) directs Federal agencies to identify and address ''disproportionately high and adverse human health or environmental effects'' of their actions on minority populations and low-income populations to the greatest extent practicable and permitted by law. The EPA defines environmental justice (EJ) as ''the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.'' The EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.''

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to review state choices, and approve those choices if they meet the minimum criteria of the Act. As articulated in this final action, the EPA is determining that certain SIPs do not meet certain minimum requirements, and the EPA is disapproving those SIPs. Specifically, this action disapproves certain SIP submissions as not containing the necessary provisions to satisfy ''good neighbor'' requirements under CAA section 110(a)(2)(D)(i)(I). The EPA did not perform an EJ analysis and did not consider EJ in this action. The CAA and applicable implementing regulations neither prohibit nor require such an evaluation. In a wholly separate regulatory action, the EPA will fully address the CAA ''good neighbor'' requirements under section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS as it regards the SIP disapprovals included in this final action. Consideration of EJ is not required as part of this action, and there is no information in the record inconsistent with the stated goal of E.O. 12898 of achieving EJ for people of color, low-income populations, and Indigenous peoples.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

L. Judicial Review

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the D.C. Circuit: (i) when the agency action consists of ''nationally applicable regulations promulgated, or final actions taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, but ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.'' For locally or regionally applicable final actions, the CAA reserves to the EPA complete discretion whether to invoke the exception in (ii).[337]

This rulemaking is ''nationally applicable'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is applying a uniform legal interpretation and common, nationwide analytical methods with respect to the requirements of CAA section 110(a)(2)(D)(i)(I) concerning interstate transport of pollution (*i.e.,* ''good neighbor'' requirements) to disapprove SIP submissions that fail to satisfy these requirements for the 2015 ozone NAAQS. Based on these analyses, the EPA is disapproving SIP submittals for the 2015 ozone NAAQS for 21 states located across a wide geographic area in eight of the ten EPA Regions and ten Federal judicial circuits. Given that on its face this action addresses implementation of the good neighbor requirements of CAA section 110(a)(2)(D)(i)(I) in a large number of states located across the country and given the interdependent nature of interstate pollution transport and the common core of knowledge and analysis involved in evaluating the submitted SIPs, this is a ''nationally applicable'' action within the meaning of CAA section 307(b)(1).

In the alternative, to the extent a court finds this action to be locally or regionally applicable, the Administrator is exercising the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of ''nationwide scope or effect'' within the meaning of CAA section 307(b)(1). In this final action, the EPA is interpreting and applying section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS based on a common core of nationwide policy judgments and technical analysis concerning the interstate transport of pollutants throughout the continental U.S. In particular, the EPA is applying here the same, nationally consistent 4-step interstate transport framework for assessing obligations for the 2015 ozone NAAQS that it has applied in other nationally applicable rulemakings, such as CSAPR, the CSAPR Update, and the Revised CSAPR Update. The EPA is relying on the results from nationwide photochemical grid modeling using a 2016 base year and 2023 projection year as the primary basis for its assessment of air quality conditions and pollution contribution levels at Step 1 and Step 2 of that 4-step framework and applying a nationally uniform approach to the identification of nonattainment and

[337] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

maintenance receptors across the entire geographic area covered by this final action.[338] The EPA has also evaluated each state's arguments for the use of alternative approaches or alternative sets of data with an eye to ensuring national consistency and avoiding inconsistent or inequitable results among upwind states (*i.e.,* those states for which good neighbor obligations are being evaluated in this action) and between upwind and downwind states (*i.e.,* those states that contain receptors signifying ozone nonattainment or maintenance problems).

The Administrator finds that this is a matter on which national uniformity in judicial resolution of any petitions for review is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the basic law under the Act. The Administrator also finds that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results for different states, and that a nationally consistent approach to the CAA's mandate concerning interstate transport of ozone pollution constitutes the best use of agency resources. The EPA's responses to comments on the appropriate venue for petitions for review are contained in the RTC document.

For these reasons, this final action is nationally applicable or, alternatively, the Administrator is exercising the complete discretion afforded to him by the CAA and finds that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1) and is publishing that finding in the **Federal Register**. Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the District of Columbia Circuit by April 14, 2023.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Ozone.

Michael S. Regan,
Administrator.

For the reasons set forth in the preamble, 40 CFR part 52 is amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart B—Alabama

■ 2. Section 52.56 is added to read as follows:

§ 52.56 Control strategy: Ozone.

(a) The state implementation plan (SIP) revision submitted on June 21, 2022, addressing Clean Air Act section 110(a)(2)(D)(i)(I) (prongs 1 and 2) for the 2015 ozone national ambient air quality standards (NAAQS) is disapproved.

(b) [Reserved]

Subpart E—Arkansas

■ 3. Section 52.174 is amended by adding paragraph (b) to read as follows:

§ 52.174 Control strategy and regulations: Ozone.

* * * * *

(b) The portion of the SIP submittal from October 10, 2019, addressing Clean Air Act section 110(a)(2)(D)(i)(I) for the 2015 ozone national ambient air quality standards (NAAQS) is disapproved.

Subpart F—California

■ 4. Section 52.223 is amended by adding paragraph (p)(7) to read as follows:

§ 52.223 Approval status.

* * * * *

(p) * * *

(7) The interstate transport requirements for Significant Contribution to Nonattainment (Prong 1) and Interstate Transport—Interference with Maintenance (Prong 2) of Clean Air Act (CAA) section 110(a)(2)(D)(i)(I).

■ 5. Section 52.283 is amended by adding paragraph (h) to read as follows:

§ 52.283 Interstate Transport.

* * * * *

(h) *2015 ozone NAAQS.* The 2018 Infrastructure SIP Revision, submitted on October 1, 2018, does not meet the following specific requirements of Clean Air Act section 110(a)(2)(D)(i)(I) for the 2015 ozone national ambient air quality standards (NAAQS).

(1) The requirements of CAA section 110(a)(2)(D)(i)(I) regarding significant contribution to nonattainment of the 2015 ozone NAAQS in any other State and interference with maintenance of the 2015 ozone NAAQS by any other State.

(2) [Reserved]

Subpart O—Illinois

■ 6. Section 52.720 is amended in the table in paragraph (e), under the heading "Section 110(a)(2) Infrastructure Requirements," by revising the entry for "2015 Ozone NAAQS Infrastructure Requirements" to read as follows:

§ 52.720 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED ILLINOIS NONREGULATORY AND QUASI-REGULATORY PROVISIONS

Name of SIP provision	Applicable geographic or non-attainment area	State submittal date	EPA approval date	Comments
* * * * * * *				
Section 110(a)(2) Infrastructure Requirements				

[338] In the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that the "nationwide scope or effect" exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. *See* H.R. Rep. No. 95–294 at 323, 324, reprinted in 1977 U.S.C.C.A.N. 1402–03.

EPA-APPROVED ILLINOIS NONREGULATORY AND QUASI-REGULATORY PROVISIONS—Continued

Name of SIP provision	Applicable geographic or non-attainment area	State submittal date	EPA approval date	Comments
* * *	*	*	*	* * *
2015 Ozone NAAQS Infrastructure Requirements.	Statewide ...	5/16/2019 and 9/22/2020.	2/13/2023, [INSERT **FEDERAL REGISTER** CITATION].	All CAA infrastructure elements under 110(a)(2) have been approved except (D)(i)(I) Prongs 1, 2, which are disapproved, and no action has been taken on (D)(i)(II) Prong 4.

Subpart P—Indiana

■ 7. Section 52.770 is amended in the table in paragraph (e) by adding an entry for "Section 110(a)(2) Infrastructure Requirements for the 2015 Ozone NAAQS" after the entry for "Section 110(a)(2) Infrastructure Requirements for the 2008 8-Hour Ozone NAAQS" to read as follows:

§ 52.770 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED INDIANA NONREGULATORY PROVISIONS AND QUASI-REGULATORY PROVISIONS

Title	Indiana date	EPA approval	Explanation
* *	*	*	* * *
Section 110(a)(2) Infrastructure Requirements for the 2015 Ozone NAAQS.	11/2/2018	2/13/2023, [INSERT **FEDERAL REGISTER** CITATION].	All CAA infrastructure elements have been approved except (D)(i)(I) Prongs 1 and 2, which are disapproved, and no action has been taken on the visibility portion of (D)(i)(II).
* *	*	*	* * *

Subpart S—Kentucky

■ 8. Section 52.930 is amended by adding paragraph (n) to read as follows:

§ 52.930 Control strategy: Ozone.

* * * * *

(n) *Disapproval.* The state implementation plan (SIP) revision submitted on January 11, 2019, addressing Clean Air Act section 110(a)(2)(D)(i)(I) (prongs 1 and 2) for the 2015 ozone national ambient air quality standards (NAAQS) is disapproved.

Subpart T—Louisiana

■ 9. Section 52.996 is amended by adding paragraph (b) to read as follows:

§ 52.996 Disapprovals.

* * * * *

(b) The SIP submittal from November 13, 2019, addressing Clean Air Act section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS is disapproved.

Subpart V—Maryland

■ 10. Section 52.1076 is amended by adding paragraph (gg) to read as follows:

§ 52.1076 Control strategy plans for attainment and rate-of-progress: Ozone.

* * * * *

(gg) *Disapproval.* EPA is disapproving Maryland's October 16, 2019, State Implementation Plan (SIP) revision intended to address the Clean Air Act (CAA) section 110(a)(2)(D)(i)(I) interstate transport requirements for the 2015 8-hour ozone national ambient air quality standard (NAAQS).

Subpart X—Michigan

■ 11. Section 52.1170 is amended in the table in paragraph (e), under the heading "Infrastructure," by revising the entry for "Section 110(a)(2) infrastructure requirements for the 2015 ozone NAAQS" to read as follows:

§ 52.1170 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED MICHIGAN NONREGULATORY AND QUASI-REGULATORY PROVISIONS

Name of nonregulatory SIP provision	Applicable geographic or non-attainment area	State submittal date	EPA approval date	Comments
* *	*	*	*	* *
		Infrastructure		

EPA-APPROVED MICHIGAN NONREGULATORY AND QUASI-REGULATORY PROVISIONS—Continued

Name of nonregulatory SIP provision	Applicable geographic or non-attainment area	State submittal date	EPA approval date	Comments
* *	*	*	* *	* *
Section 110(a)(2) infrastructure requirements for the 2015 ozone NAAQS.	Statewide ...	3/8/2019	2/13/2023, [INSERT **FEDERAL REGISTER** CITATION].	*Approved CAA elements:* 110(a)(2)(A), (B), (C), (D)(i)(II) Prong 3, D(ii), (E)(i), (F), (G), (H), (J), (K), (L), and (M). *Disapproved CAA elements:* 110(a)(2)(D)(i)(I) Prongs 1 and 2, and 110(a)(2)(D)(i)(II) Prong 4. No action on CAA element 110(1)(2)(E)(ii).
* *	*	*	* *	* *

Subpart Y—Minnesota

■ 12. Section 52.1220 is amended in the table in paragraph (e) by revising the entry for ''Section 110(a)(2) Infrastructure Requirements for the 2015 Ozone NAAQS'' to read as follows:

§ 52.1220 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED MINNESOTA NONREGULATORY PROVISIONS

Name of nonregulatory SIP provision	Applicable geographic or non-attainment area	State submittal date/ effective date	EPA approved date	Comments
* *	*	*	* *	* *
Section 110(a)(2) Infrastructure Requirements for the 2015 Ozone NAAQS.	Statewide ...	10/1/2018	2/13/2023, [INSERT **FEDERAL REGISTER** CITATION].	Fully approved for all CAA elements except transport elements of (D)(i)(I) Prong 2, which are disapproved, and no action has been taken on the visibility protection requirements of (D)(i)(II).

Subpart Z—Mississippi

■ 13. Section 52.1273 is amended by adding paragraph (b) read as follows:

§ 52.1273 Control strategy: Ozone.

* * * * *

(b) *Disapproval.* The state implementation plan (SIP) revision submitted on September 3, 2019, addressing Clean Air Act section 110(a)(2)(D)(i)(I) (prongs 1 and 2) for the 2015 ozone national ambient air quality standards (NAAQS) is disapproved.

Subpart AA—Missouri

■ 14. Section 52.1323 is amended by adding paragraph (p) to read as follows:

§ 52.1323 Approval status.

* * * * *

(p) For the 2015 8-hour ozone NAAQS:

(1) *Disapproval.* Missouri state implementation plan (SIP) revision submitted on June 10, 2019, to address the Clean Air Act (CAA) infrastructure requirements of section 110(a)(2) for the 2015 8-hour ozone NAAQS, is disapproved for section 110(a)(2)(D)(i)(I) (prongs 1 and 2).

(2) [Reserved]

Subpart DD—Nevada

■ 15. Section 52.1472 is amended by adding paragraph (k) to read as follows:

§ 52.1472 Approval status.

* * * * *

(k) *2015 8-hour ozone NAAQS.* The SIP submittal from October 1, 2018, is disapproved for Clean Air Act (CAA) section 110(a)(2)(D)(i)(I) (prongs 1 and 2) for the NDEP, Clark County, and Washoe County portions of the Nevada SIP submission.

Subpart FF—New Jersey

■ 16. Section 52.1586 is amended by adding paragraph (c) and reserved paragraph (d) to read as follows:

§ 52.1586 Section 110(a)(2) infrastructure requirements.

* * * * *

(c) *2015 8-hour ozone NAAQS*—(1) *Disapproval.* New Jersey SIP revision submitted on May 13, 2019, to address the CAA infrastructure requirements of section 110(a)(2) for the 2015 8-hour ozone NAAQS, is disapproved for section 110(a)(2)(D)(i)(I) (prongs 1 and 2).

(2) [Reserved]

(d) [Reserved]

Subpart HH—New York

■ 17. Section 52.1683 is amended by adding paragraph (v) to read as follows:

§ 52.1683 Control strategy: Ozone.

* * * * *

(v) *Disapproval.* The portion of the SIP revision submitted on September 25, 2018, addressing Clean Air Act section 110(a)(2)(D)(i)(I) (prongs 1 and 2) for the 2015 ozone NAAQS is disapproved.

Subpart KK—Ohio

■ 18. Section 52.1870 is amended in the table in paragraph (e), under ''Infrastructure Requirements,'' by revising the entry for ''Section 110(a)(2) infrastructure requirements for the 2015 ozone NAAQS'' to read as follows:

§ 52.1870 Identification of plan.

* * * * *

(e) * * *

EPA-APPROVED OHIO NONREGULATORY AND QUASI-REGULATORY PROVISIONS

Title	Applicable geographic or non-attainment area	State date	EPA approval	Comments
* * *	*	*	*	*
Infrastructure Requirements				
* * *	*	*	*	*
Section 110(a)(2) infrastructure requirements for the 2015 ozone NAAQS.	Statewide ...	9/28/2018	2/13/2023, [INSERT **FEDERAL REGISTER** CITATION].	Approved CAA elements: 110(a)(2)(A), (B), (C), (D)(i)(II) prongs 3 and 4, (E), (F), (G), (H), (J), (K), (L), and (M). Elements (D)(i)(I) prongs 1 and 2 are disapproved.
* * *	*	*	*	*

Subpart LL—Oklahoma

■ 19. Section 52.1922 is amended by adding paragraph (c) to read as follows:

§ 52.1922 Approval status.

* * * * *

(c) The portion of the SIP submittal from October 25, 2018, addressing Clean Air Act section 110(a)(2)(D)(i)(I) for the 2015 ozone national ambient air quality standards (NAAQS) is disapproved.

Subpart SS—Texas

■ 20. Section 52.2275 is amended by:

■ a. Removing the first paragraph (m); and

■ b. Adding paragraph (o).

The addition reads as follows:

§ 52.2275 Control strategy and regulations: Ozone.

* * * * *

(o) *Disapproval.* The portion of the SIP submittal from September 12, 2018, addressing Clean Air Act section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS is disapproved.

Subpart XX—West Virginia

■ 21. Section 52.2520 is amended in the table in paragraph (e) by adding the entry ''Section 110(a)(2) Infrastructure Requirements for the 2015 8-Hour Ozone NAAQS'' at the end of the table to read as follows:

§ 52.2520 Identification of plan.

* * * * *

(e) * * *

Name of non-regulatory SIP revision	Applicable geographic area	State submittal date	EPA approval date	Additional explanation
* * *	*	*	*	*
Section 110(a)(2) Infrastructure Requirements for the 2015 8-Hour Ozone NAAQS.	Statewide ...	2/4/2019	2/13/2023, [INSERT **FEDERAL REGISTER** CITATION].	Disapproval—EPA is disapproving West Virginia's February 4, 2019, State Implementation Plan (SIP) revision intended to address the CAA section 110(a)(2)(D)(i)(I) interstate transport requirements for the 2015 8-hour ozone national ambient air quality standard (NAAQS).

Subpart YY—Wisconsin

■ 22. Section 52.2591 is amended by adding paragraph (l) to read as follows:

§ 52.2591 Section 110(a)(2) infrastructure requirements.

* * * * *

(l) *Partial approval/disapproval.* In a September 14, 2018, submission, WDNR certified that the State has satisfied the infrastructure SIP requirements of section 110(a)(2)(A) through (H), and (J) through (M) for the 2015 ozone NAAQS. For section 110(a)(2)(D)(i)(I), prong 1 is approved and prong 2 is disapproved. EPA did not take action on any other elements. We will address the remaining requirements in a separate action.

[FR Doc. 2023–02407 Filed 2–10–23; 8:45 am]

BILLING CODE 6560–50–P

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit C

Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (Apr. 6, 2022)

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52, 75, 78 and 97

[EPA–HQ–OAR–2021–0668; FRL 8670–01–OAR]

RIN 2060–AV51

Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes Federal Implementation Plan (FIP) requirements to address twenty-six states' obligations to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 ozone National Ambient Air Quality Standard (NAAQS) in other states. The U.S. Environmental Protection Agency (EPA) is proposing this action under the ''good neighbor'' or ''interstate transport'' provision of the Clean Air Act (CAA or Act). The Agency proposes establishing nitrogen oxides emissions budgets requiring fossil fuel-fired power plants in 25 states to participate in an allowance-based ozone season trading program beginning in 2023. The Agency is also proposing to establish nitrogen oxides emissions limitations applicable to certain other industrial stationary sources in 23 states with an earliest possible compliance date of 2026. These industrial source types are: Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

DATES: Comments must be received on or before June 6, 2022.

Public Hearing: The EPA will hold a virtual public hearing on April 21, 2022. Please refer to the **SUPPLEMENTARY INFORMATION** section for additional information on the public hearing.

Information Collection Request (ICR): Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before May 6, 2022.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2021–0668; via the Federal eRulemaking Portal: *https://www.regulations.gov/* (our preferred method). Follow the online instructions for submitting comments.

Instructions: All submissions received must include the Docket ID No. for this rulemaking. Comments received may be posted without change to *https://www.regulations.gov/,* including any personal information provided. For detailed instructions on sending comments and additional information on the rulemaking process, see the ''Public Participation'' heading of the **SUPPLEMENTARY INFORMATION** section of this document. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room are open to the public by appointment only to reduce the risk of transmitting COVID–19. Our Docket Center staff also continues to provide remote customer service via email, phone, and webform. Hand deliveries and couriers may be received by scheduled appointment only. For further information on EPA Docket Center services and the current status, please visit us online at *https://www.epa.gov/dockets.*

The virtual public hearing will be held on April 21, 2022. The virtual public hearing will convene at 10 a.m. Eastern Time (ET) and will conclude at 7 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. For information or questions about the public hearing, please contact Ms. Holly DeJong at *Dejong.holly@epa.gov.* The EPA will announce further details at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.* Refer to the **SUPPLEMENTARY INFORMATION** section for additional information.

FOR FURTHER INFORMATION CONTACT: Ms. Elizabeth Selbst, Air Quality Policy Division, Office of Air Quality Planning and Standards (C539–01), Environmental Protection Agency, 109 TW Alexander Drive, Research Triangle Park, NC 27711; telephone number: (919)-541–3918; email address: *Selbst.elizabeth@epa.gov.*

SUPPLEMENTARY INFORMATION:

Preamble Glossary of Terms and Abbreviations

The following are abbreviations of terms used in the preamble.

2016v1 2016 Version 1 Emissions Modeling Platform
2016v2 2016 Version 2 Emissions Modeling Platform
4-Step Framework 4-Step Interstate Transport Framework
ACS American Community Survey
AEO Annual Energy Outlook
AQAT Air Quality Assessment Tool
AQMTSD Air Quality Modeling Technical Support Document
BACT Best Available Control Technology
BPT Benefit Per Ton
CAA or Act Clean Air Act
CAIR Clean Air Interstate Rule
CBI Confidential Business Information
CCR Coal Combustion Residual
CDC Centers for Disease Control and Prevention
CEMS Continuous Emissions Monitoring Systems
CES Clean Energy Standards
CHP Combined Heat and Power
CMDB Control Measures Database
CMV Commercial Marine Vehicle
CoST Control Strategy Tool
CPT Cost Per Ton
CSAPR Cross-State Air Pollution Rule
EGU Electric Generating Unit
EIA U.S. Energy Information Agency
EISA Energy Independence and Security Act
ELG Effluent Limitation Guidelines
E.O. Executive Order
EPA or the Agency United States Environmental Protection Agency
FFS Finding of Failure To Submit
FIP Federal Implementation Plan
GIS Geographic Information System
HDGHG Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles
HEDD High Electricity Demand Days
ICI Industrial, Commercial, and Institutional
I/M Inspection and Maintenance
IPM Integrated Planning Model
LNB Low-NO_X Burners
MJO Multi-Jurisdictional Organization
MOVES Motor Vehicle Emission Simulator
MSAT2 Mobile Source Air Toxics Rule
MWC Municipal Waste Combustor
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NEEDS National Electric Energy Data System
NEI National Emissions Inventory
NESHAP National Emissions Standards for Hazardous Air Pollutants
No SISNOSE No Significant Economic Impact on a Substantial Number of Small Entities
Non-EGU Non-Electric Generating Unit
NO_X Nitrogen Oxides
NSPS New Source Performance Standard
NREL National Renewable Energy Lab
NTTAA National Technology Transfer and Advancement Act
OFA Over-Fire Air
OMB United States Office of Management and Budget
OSAT/APCA Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis
OTC Ozone Transport Commission
OTR Ozone Transport Region
OTSA Oklahoma Tribal Statistical Area
PEMS Predictive Emissions Monitoring Systems

$PM_{2.5}$ Fine Particulate Matter
ppb parts per billion
ppm parts per million
ppmvd parts per million by volume, dry
PRA Paperwork Reduction Act
RACT Reasonably Available Control Technology
RFA Regulatory Flexibility Act
RICE Reciprocating Internal Combustion Engines
ROP Rate of Progress
RPS Renewable Portfolio Standards
RRF Relative Response Factor
SAFE Safer Affordable Fuel-Efficient Vehicles Rule
SAFETEA Safe, Accountable, Flexible, Efficient, Transportation Equity Act
SCR Selective Catalytic Reduction
SIP State Implementation Plan
SMOKE Sparse Matrix Operator Kernel Emissions
SNCR Selective Non-Catalytic Reduction
SO_2 Sulfur Dioxide
tpd ton per day
TSD Technical Support Document
UMRA Unfunded Mandates Reform Act
VMT Vehicle Miles Traveled
VOCs Volatile Organic Compounds
WRAP Western Regional Air Partnership
WRF Weather Research and Forecasting

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I. Executive Summary

This proposed rule would resolve the interstate transport obligations of 26 states under CAA section 110(a)(2)(D)(i)(I), referred to as the ''good neighbor provision'' or the ''interstate transport provision'' of the Act, for the 2015 ozone NAAQS. On October 1, 2015, the EPA revised the primary and secondary 8-hour standards for ozone to 70 parts per billion (ppb).[1] States were required to provide ozone infrastructure State Implementation Plan (SIP) submissions to fulfill interstate transport obligations for the 2015 ozone NAAQS by October 1, 2018.

The EPA proposes to make a finding that interstate transport of ozone precursor emissions from 26 upwind states (Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states, based on projected nitrogen oxides (NO_X) emissions in the 2023 ozone season. The EPA is proposing to issue FIP requirements to eliminate interstate transport of ozone precursors from these 26 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in other states.

The EPA is proposing FIPs for 23 states for which the Agency has not approved an ozone transport SIP that was submitted for the 2015 ozone NAAQS: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, Utah, West Virginia, Wisconsin, and Wyoming. In this proposed rule, the EPA is proposing to issue FIPs for two states—Pennsylvania and Virginia—for which the EPA issued a Finding of Failure to Submit for 2015 ozone transport SIPs with an effective date of January 6, 2020. Under CAA section 301(d)(4), the EPA proposes to extend FIP requirements to apply in Indian country located within the upwind geography of the proposed rule, including Indian reservation lands and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction.[2] The EPA is also proposing a FIP for Delaware and an error correction for the Agency's May 1, 2020, approval at 85 FR 25307 of the interstate transport elements for Delaware's October 11, 2018, and December 26, 2019, ozone infrastructure SIP submissions.

In this proposed rule, the EPA proposes to establish new ozone season NO_X emissions budgets beginning in 2023 for Electric Generating Unit (EGU) sources. The EPA is also proposing to establish emissions limitations beginning in 2026 for certain other industrial stationary sources (referred to generally as ''non-Electric Generating Units'' (non-EGUs)). Taken together, these strategies will fully eliminate the covered states' significant contribution to downwind ozone air quality problems in other states.

The EPA proposes to implement the necessary emissions reductions as follows. The proposed FIP requirements establish ozone season NO_X emissions budgets for EGUs in 25 states (Alabama, Arkansas, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) and require EGUs in these states to participate in a revised version of the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 Trading Program that was previously established in the Revised CSAPR Update.[3] The EPA proposes to amend existing FIPs for 12 states currently participating in the CSAPR NO_X Ozone Season Group 3 Trading Program (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) to replace their existing emissions budgets established in the Revised CSAPR Update (with respect to the 2008 ozone NAAQS) with new

[1] *See* 80 FR 65291 (October 26, 2015).

[2] In general, specific tribal names or reservations are not identified separately in this proposal except as needed. See Section IV.C.2 of this notice for further discussion.

[3] As explained in Section VI.C.1 of this notice, EPA proposes finding that EGU sources within the State of California are sufficiently controlled such that no further emissions reductions are needed from them to eliminate significant contribution to downwind states.

emissions budgets. For eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program under SIPs or FIPs, the EPA is proposing to issue new FIPs for two states (Alabama and Missouri) and amend existing FIPs for six states (Arkansas, Mississippi, Oklahoma, Tennessee, Texas, and Wisconsin) to transition EGU sources in these states from the Group 2 program to the revised Group 3 trading program, beginning with the 2023 ozone season. EPA proposes to issue new FIPs for five states not currently covered by any CSAPR NO_X ozone season trading program: Delaware, Minnesota, Nevada, Utah, and Wyoming.

Under this proposed rulemaking, emissions reductions in the selected control stringency would be achieved as soon as they are available, some of which are scheduled to occur by the 2023 ozone season and prior to the August 3, 2024, attainment date for areas classified as Moderate nonattainment for the 2015 ozone NAAQS, and the rest of which occur as soon as possible thereafter through the 2026 ozone season, prior to the August 3, 2027, attainment date for areas classified as Serious nonattainment for the 2015 ozone NAAQS. As discussed in Section VII.A.2 of this notice, the EPA proposes to find that the 2026 ozone season is as expeditious as practicable to implement substantial emissions reductions from potential new post-combustion control installations at EGUs as well as from installation of new pollution controls at non-EGUs.

These EGU emissions reductions are scheduled to begin in the 2026 ozone season based on the feasibility of control installation for EGUs in 22 states that remain linked to downwind nonattainment and maintenance receptors in that year. These 22 states are: Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. The additional emissions reductions required for these states are based primarily on the potential retrofit of additional post-combustion controls for NO_X on most coal steam EGUs and a portion of oil/gas steam EGUs that are currently lacking such controls.

In this proposed rule, the EPA introduces additional features to the allowance-based trading program approach for EGUs, including dynamic adjustments of the emissions budgets over time and backstop daily emissions rate limits for most coal-fired units, that will help maintain control stringency over time and improve emissions performance at individual units, providing further assurance that existing pollution controls will be operated during the ozone season and that the emission reductions necessary to meet good neighbor requirements will be achieved.

The EPA proposes to find that NO_X emissions from non-EGU sources are significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS and that cost-effective controls for NO_X emissions reductions are available in certain industrial source categories that would result in meaningful air quality improvements in downwind receptors. The EPA proposes to require emissions limitations beginning in 2026 for non-EGUs located within 23 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. The proposed rule establishes NO_X emissions limitations during the ozone season for the following unit types for sources in non-EGU industries: Reciprocating internal combustion in Pipeline Transportation of Natural Gas sources; kilns in Cement and Cement Product Manufacturing sources; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing sources; furnaces in Glass and Glass Product Manufacturing sources; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

A. Purpose of the Regulatory Action

The purpose of this rulemaking is to protect public health and the environment by reducing interstate transport of certain air pollutants that significantly contribute to nonattainment, or interfere with maintenance, of the 2015 ozone NAAQS in other states. Ground-level ozone has detrimental effects on human health as well as vegetation and ecosystems. Acute and chronic exposure to ozone in humans is associated with premature mortality and a number of morbidity effects, such as asthma exacerbation. Ozone exposure can also negatively impact ecosystems by limiting tree growth, causing foliar injury, and changing ecosystem community composition. Section IV of this proposed rule provides additional evidence of the harmful effects of ozone exposure on human health and the environment. Studies have established that ozone air pollution can be transported over hundreds of miles, with elevated ground-level ozone concentrations occurring in rural and metropolitan areas.[4 5] Assessments of ozone control approaches have concluded that control strategies targeting reduction of NO_X emissions are an effective method to reduce regional-scale ozone transport.[6]

CAA section 110(a)(2)(D)(i)(I) requires states to prohibit emissions that will contribute significantly to nonattainment or interfere with maintenance in any other state with respect to any primary or secondary NAAQS.[7] States fulfill their primary responsibility to address interstate transport emissions under the good neighbor provision by submitting SIPs containing enforceable emission limitations and other control measures, means, or techniques required to address the interstate transport provision. Within 3 years of the EPA promulgating a new or revised NAAQS, states are required to provide infrastructure SIP submittals, including good neighbor SIPs. *See* CAA section 110(a)(1) and (2). When states do not submit approvable interstate transport SIPs or fail to submit interstate transport SIPs by the statutory deadline, the CAA requires the EPA to issue FIPs to ensure that states eliminate their significant contribution to downwind air quality problems under the good neighbor provision. *See generally* CAA section 110(k) and 110(c). As such, in this proposed rule, the EPA is proposing requirements to fully address good neighbor obligations for these states for the 2015 ozone NAAQS under its authority to promulgate FIPs under CAA section 110(c).

It is appropriate to issue this proposal at this time for at least three reasons. First, this proposal will ensure that necessary emissions reductions to eliminate significant contribution are achieved as expeditiously as practicable. The EPA's anticipated timing will provide for all possible emissions reductions to go into effect

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[4] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[5] Liao, K. et al. (2013) Impacts of interstate transport of pollutants on high ozone events over the Mid-Atlantic United States. Atmospheric Environment 84, 100–112.

[6] *See* 82 FR 51238, 51248 (November 3, 2017) [citing 76 FR 48208, 48222 (August 8, 2011)] and 63 FR 57381 (October 27, 1998).

[7] 42 U.S.C. 7410(a)(2)(D)(i)(I).

beginning in the 2023 ozone season, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date are proposed to take effect as expeditiously as practicable, with the full suite of emissions reductions taking effect by the 2026 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. As explained in sections V.A, VI, and VII.A of this proposed rule, these proposed timeframes for eliminating significant contribution are consistent with the provisions of title I of the CAA. Second, this proposal will provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes necessary to eliminate significant contribution. Third, for all of the states included in this proposed rule, the EPA's modeling and analysis indicate that additional emissions reductions beyond those which are provided in any state's 2015 ozone transport SIP are necessary to eliminate significant contribution.

The EPA anticipates that the states covered in this proposed FIP rulemaking may not have adequate provisions in their SIPs to address their interstate transport obligations for the 2015 ozone NAAQS. As discussed in Section IV.B.2 of this proposed rule, the EPA has, for certain states, made findings that the state failed to submit a complete good neighbor SIP revision for the 2015 ozone NAAQS. For certain other states, the EPA has proposed, but has not finalized, actions disapproving good neighbor SIP revisions. And for other states, the EPA has not yet proposed action on their good neighbor SIP submittals, but these submittals are currently under review, and EPA intends to act on these submittals in the coming months. The EPA will not finalize this proposed FIP action for any state for which it has not taken final action either disapproving that state's good neighbor SIP submittal or finding that the state failed to submit a complete SIP.

The EPA conducted air quality modeling for future analytic years to identify (1) the downwind areas that are expected to have trouble attaining or maintaining the 2015 ozone NAAQS in the future and (2) the contribution of ozone transport from upwind states to the downwind air quality problems. Section V of this proposed rule provides a full description of the results of EPA's air quality modeling and relevant analyses for the proposed rulemaking. Based on EPA's air quality analysis, a total of 27 upwind states are linked above the 1 percent of the NAAQS threshold to downwind air quality problems in other states. The EPA had previously approved 2015 ozone transport SIPs submitted by two of these states—Oregon and Delaware—and proposes in this proposed rule to issue an error correction for its prior approval of Delaware's 2015 ozone transport SIP (*see* Section IV.C.1 of this notice for additional information on the proposed error correction). The EPA is not proposing any change to its prior approval of Oregon's 2015 ozone transport SIP, a determination which is further described in Section V.F of this proposed rule.

In this proposed rule, the EPA is proposing to issue FIP requirements for 26 states, which include emissions reductions for EGU sources within the borders of 25 states (described in Section VII.B of this proposed rule) and include emissions reductions for non-EGU sources within the borders of 23 states (described in Section VII.C in this proposed rule). Based on EPA's assessment of remaining air quality issues and additional emissions control strategies, the EPA further proposes to find that the EGU and non-EGU NO_X emissions reductions required in the proposed rule would fully eliminate these states' significant contributions to downwind air quality problems for the 2015 ozone NAAQS. By eliminating significant contribution from these upwind states, this rule, if finalized as proposed, will make substantial and meaningful improvements in air quality by reducing ozone levels at the identified downwind receptors as well as many other areas of the country.

1. Emissions Limitations for EGUs Established by the Proposed Rule

In this proposed rule, the EPA proposes to issue FIP requirements that include new NO_X ozone season emissions budgets for EGU sources within the borders of the 25 states listed in Table I.A–1, with implementation of these emissions budgets beginning in the 2023 ozone season. The EPA proposes to find that these emissions reductions are necessary to address upwind states' interstate transport obligations for the 2015 ozone NAAQS.

TABLE I.A–1—PROPOSED LIST OF 25 COVERED STATES FOR EGU EMISSIONS REDUCTIONS FOR THE 2015 8-HOUR OZONE NAAQS

State
Alabama
Arkansas
Delaware
Illinois
Indiana
Kentucky
Louisiana
Maryland
Michigan
Minnesota
Mississippi
Missouri
Nevada
New Jersey
New York
Ohio
Oklahoma
Pennsylvania
Tennessee
Texas
Utah
Virginia
West Virginia
Wisconsin
Wyoming

The EPA proposes to expand the CSAPR NO_X Ozone Season Group 3 Trading Program beginning in the 2023 ozone season. Specifically, the FIPs would require power plants within the borders of the 25 states listed in Table I.A–1 to participate in a revised version of the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of twelve states currently participating in the Group 3 Trading Program under FIPs or SIPs would remain in the program, with revised provisions beginning in the 2023 ozone season, under this proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. The FIPs would also require affected EGUs within the borders of eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'') under existing FIPs or existing SIPs to transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period: (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin).[8] Finally, the EPA is

[8] Six of these eight states (Arkansas, Mississippi, Oklahoma, Tennessee, Texas, and Wisconsin) currently participate in the federal Group 2 trading program pursuant to the FIPs finalized in the CSAPR Update, so the FIPs proposed in this rulemaking would amend the existing FIPs for these

proposing to issue new FIPs for EGUs within the borders of five states not currently covered by any CSAPR trading program for seasonal NO_X emissions: Delaware, Minnesota, Nevada, Utah, and Wyoming. If the proposed FIP is finalized, sources in these states would enter the Group 3 trading program in the 2023 control period following the effective date of the final rule.[9] In all cases, if the state submits and the EPA approves a SIP revision that would fully achieve the emissions reductions needed to meet the state's good neighbor obligations with respect to the 2015 ozone NAAQS before a final rule is promulgated in this rulemaking, the proposed FIP requirements summarized above would not be finalized. Refer to Section VII.B of this proposed rule for details on EGU regulatory requirements.

2. Emissions Limitations for Non-EGU Stationary Point Sources Established by the Proposed Rule

In this proposed rule, the EPA proposes to issue FIP requirements that include new NO_X emissions limitations for non-Electric Generating Unit (non-EGU) sources in 23 states, with earliest possible compliance dates for these emissions limitations beginning in 2026. The EPA proposes to require emissions reductions from non-EGU sources to address interstate transport obligations for the 2015 ozone NAAQS for the 23 states listed in Table I.A–2.

TABLE I.A–2—PROPOSED LIST OF 23 COVERED STATES FOR NON-EGU EMISSIONS REDUCTIONS FOR THE 2015 8-HOUR OZONE NAAQS

State
Arkansas
California
Illinois
Indiana
Kentucky
Louisiana
Maryland
Michigan
Minnesota
Mississippi
Missouri
Nevada
New Jersey
New York
Ohio
Oklahoma
Pennsylvania
Texas
Utah
Virginia
West Virginia
Wisconsin
Wyoming

states. The other two states (Alabama and Missouri) have already replaced the FIPs finalized in the CSAPR Update with approved SIP revisions that require their EGUs to participate in state Group 2 trading programs integrated with the federal Group 2 trading program, so the FIPs proposed in this action would constitute new FIPs for these states, and the EPA would cease implementation of the state Group 2 trading programs included in the two states' SIPs.

[9] Two states, Kansas and Iowa, will remain in the Group 2 Trading Program.

The EPA is proposing to require emissions limitations for the following unit types in non-EGU industries: Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas sources; kilns in Cement and Cement Product Manufacturing sources; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing sources; furnaces in Glass and Glass Product Manufacturing sources; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. Refer to Table III.A–1 for a list of North American Industry Classification System (NAICS) codes for each entity included for regulation under this proposed rule.

3. Proposed Error Correction for Previously Approved 2015 Ozone Transport SIP

The EPA proposes to make an error correction under CAA section 110(k)(6) of its May 1, 2020, approval at 85 FR 25307 of the interstate transport elements for Delaware's October 11, 2018, and December 26, 2019, ozone infrastructure SIP submissions as satisfying the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. The EPA proposes to determine that the basis for the prior SIP approval is invalidated by the Agency's more recent technical evaluation of air quality modeling performed in support of the proposed rule,[10] and that Delaware has unresolved interstate transport obligations for the 2015 ozone NAAQS. In this proposed rule, the EPA is also exercising its authority to propose to issue a FIP for Delaware in light of these unresolved interstate transport obligations.

[10] *See* the Air Quality Modeling Technical Support Document (AQM TSD) in the docket for this proposed rule.

4. Request for Comment on All Aspects of the Proposal

Throughout this proposed rule, unless noted otherwise, the EPA is requesting comments on all aspects of the proposal to enable the Agency to develop a final rule that, consistent with our responsibilities under section 110 of the CAA, eliminates air pollution that significantly contributes to nonattainment or interference with maintenance of the 2015 ozone NAAQS. This proposed rule adheres closely to the legal and analytical framework that the EPA has applied in the past in implementing the good neighbor provision of the CAA, as well as the ample case law reviewing that framework. At the same time, in this proposal, the EPA is applying lessons learned from the performance of regulatory programs established by previous ozone transport rulemakings, as well as updating the Agency's application of the 4-step interstate transport framework with recent information on the nature of ozone transport and emissions reductions opportunities in order to eliminate significant contribution for the more stringent 2015 ozone NAAQS under the good neighbor provision. The EPA invites comments and information to support its efforts to improve the regulation of interstate ozone transport under the good neighbor provision and to fulfill our mission to protect human health and the environment. The EPA will carefully consider information provided in response to this request and will respond to comments submitted through the regulatory docket in the final rule.

B. Summary of the Major Provisions of the Regulatory Action

The EPA is applying the 4-step interstate transport framework developed in CSAPR, the CSAPR Update, the Revised CSAPR Update, and other previous ozone transport rules to propose to further limit NO_X emissions from EGU sources within the borders of 25 states during the ozone season (May 1 through September 30) and to limit ozone season NO_X emissions from non-EGU sources in 23 states to reduce interstate ozone transport under the authority provided in CAA section 110(a)(2)(D)(i)(I). The 4-step interstate transport framework provides a stepwise method for the EPA to propose rule provisions that are required to address the requirements of the good neighbor provision for the 2015 ozone NAAQS: (1) Identifying downwind receptors that are expected to have problems attaining or maintaining the NAAQS; (2) determining which upwind states contribute to these identified problems in amounts sufficient to ''link'' them to the downwind air quality problems (*i.e.,* in this proposed rule, a contribution threshold of 1 percent of the NAAQS); (3) for states linked to downwind air quality problems, identifying upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implementing the necessary emissions reductions through enforceable measures. In this proposed rule, the EPA applies the 4-step framework to evaluate upwind states' obligations to reduce interstate transport of ozone precursor emissions for the 2015 ozone NAAQS. The remainder of this section provides a general overview of the EPA's application of the 4-step framework as it applies to major provisions of the proposed rule; additional details regarding EPA's proposed rule approach are found in Section IV of this proposed rule.

In order to apply the first step of the 4-step framework to the 2015 ozone NAAQS, the EPA performed air quality modeling to project ozone concentrations at air quality monitoring sites in 2023, 2026, and 2032.[11] The EPA evaluated projected ozone concentrations for the 2023 analytic year at individual monitoring sites and considered current ozone monitoring data at these sites to identify receptors that are anticipated to have problems attaining or maintaining the 2015 ozone NAAQS. This analysis was then repeated using projected ozone concentrations for 2026 and 2032.

To apply the second step of the framework, the EPA used air quality modeling to quantify the contributions from upwind states to ozone concentrations in 2023 and 2026 at downwind receptors.[12] Once quantified, EPA then evaluated these contributions relative to a screening threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb).[13] States with contributions that equaled or exceeded 1 percent of the NAAQS were identified as warranting further analysis at Step 3 of the four-step framework to determine if the upwind state significantly contributes to nonattainment or interference with maintenance in a downwind state. States with contributions below 1 percent of the NAAQS were considered not to significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind states. Based on EPA's most recent air quality modeling and contribution analysis using 2023 as the analytic year, the EPA proposes to find that the following 27 states have contributions that equal or exceed 1 percent of the 2015 ozone NAAQS, and, thereby, warrant further analysis of significant contribution to nonattainment or interference with maintenance of the NAAQS: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. Further evaluation of the locations in California to which Oregon was linked at Step 2 leads the EPA to conclude downwind areas represented by these monitoring sites should not be considered interstate ozone transport receptors. Therefore, the EPA is not proposing any further emissions reductions from the state of Oregon because there is no significant contribution required to be eliminated under the interstate transport provision, as described in Section V.F of this proposed rule.

Based on the air quality analysis presented in Section V of this proposed rule, the EPA proposes to find that in the absence of additional emissions reductions in those states the majority of the states that the EPA is proposing to participate in the Ozone Season Group 3 Trading Program will continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season, with the exception of Alabama, Delaware, and Tennessee. As a result, EPA's evaluation of emissions reduction potential at Step 3 for Alabama, Delaware, and Tennessee is limited to emission reductions achievable by the 2023 ozone season. For each of these three states, EPA's analysis does not consider, nor does the EPA propose to require, emissions reductions at either EGUs or non-EGUs that cannot be implemented until the 2026 ozone season.

At the third step of the 4-step framework, EPA applied a multi-factor test that incorporates cost, availability of emissions reductions, and air quality impacts at the downwind receptors to determine the amount of ozone precursor emissions from the linked upwind states that ''significantly'' contribute to downwind nonattainment or maintenance receptors. In this proposed rule, the EPA proposes to apply the multifactor test described in Section VI.A of this proposed rule to both EGU and non-EGU sources. The EPA assessed the potential emissions reductions in 2023 and 2026, as well as in intervening and later years to determine the emissions reductions required to eliminate significant contribution in any future year where downwind areas are projected to have potential problems attaining or maintaining the 2015 ozone NAAQS.

For EGU sources, the EPA evaluated the following set of widely-available NO_X emissions control technologies: (1) Fully operating existing selective catalytic reduction (SCR) controls, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing selective non-catalytic reduction (SNCR) controls, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting. For the reasons explained in Section VI of this proposed rule and supported by the EGU NO_X Mitigation Strategies Proposed Rule Technical Support Document (TSD) included in the docket for this proposed rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only fully operating and optimizing existing SCRs and existing SNCRs (EGU NO_X emissions controls options 1 and 3 in the list earlier) are possible for the 2023 ozone season. The EPA determined that state-of-the-art NO_X combustion controls at EGUs (emissions control option 2 in the list above) are available by the beginning of the 2024 ozone season. Based on EPA's assessment of the earliest possible timeframe for installation of new SNCR and SCRs (EGU emissions controls options 4 and 5 in the list), the EPA proposes to require emissions reductions commensurate with these controls by the beginning of the 2026 ozone season. *See* Section VI.B.1 of this proposed rule for a full description of

[11] These 3 analytic years are the last full ozone seasons before, and thus align with, upcoming attainment dates for the 2015 ozone NAAQS: August 3, 2024, for areas classified as Moderate nonattainment, August 3, 2027, for areas classified as Serious nonattainment, and August 3, 2033, for areas classified as Severe. *See* 83 FR 25776.

[12] The EPA did not perform contribution modeling for 2032 since contribution data for this year were not needed to identify upwind states to be analyzed in Step 3.

[13] *See* Section V of this proposed rule for explanation of EPA's use of the 1 percent of the NAAQS threshold in the Step 2 analysis.

EPA's analysis of NO_X emissions mitigation strategies for EGU sources.

The EPA proposes control stringency levels that maximize incremental NO_X emissions reduction potential from EGUs and corresponding downwind ozone air quality improvements to the extent feasible in each year analyzed. The EPA believes that the required controls provide cost-effective reductions of NO_X emissions that will provide substantial improvements in downwind ozone air quality to address interstate transport obligations for the 2015 ozone NAAQS in a timely manner. These controls represent greater stringency in upwind EGU controls than in EPA's most recent ozone transport rulemakings, such as the CSAPR Update and the Revised CSAPR Update. However, programs to address interstate ozone transport based on the retrofit of post-combustion controls are by no means unprecedented. In prior ozone transport rulemakings such as the NO_X SIP Call and the Clean Air Interstate Rule (CAIR), the EPA established EGU budgets premised on the widespread availability of retrofitting EGUs with post-combustion emissions controls such as SCR.[14] While these programs successfully drove many EGUs to retrofit post-combustion controls, other EGUs throughout the present geography of linked upwind states continue to operate without such controls and continue to emit at relatively high rates more than 20 years after similar units reduced these emissions under prior interstate ozone transport rulemakings.

Furthermore, the CSAPR Update provided only a partial remedy for eliminating significant contribution for the 2008 ozone NAAQS, as needed to obtain available reductions by the 2017 ozone season. In that rule, the EPA made no determination regarding the appropriateness of more stringent EGU NO_X controls that would be required for a *full* remedy for interstate transport for the 2008 ozone NAAQS. Following the remand of the CSAPR Update in *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*), the EPA again declined to require the retrofit of new post-combustion controls on EGUs in the Revised CSAPR Update, but that determination was based on a specific timing consideration: Downwind air quality problems under the 2008 ozone NAAQS were projected to resolve before post-combustion control retrofits could be accomplished on a fleetwide, regional scale. *See* 86 FR 23054, 23110 (April 30, 2021).

In this proposed rulemaking, the EPA is addressing good neighbor obligations for the more stringent 2015 ozone NAAQS, and the Agency observes ongoing and persistent contribution from upwind states to ozone nonattainment and maintenance receptors in other states under that NAAQS. As further discussed in Section VI of this proposed rule, the nature of this contribution warrants a greater degree of control stringency than the EPA determined to be necessary to eliminate significant contribution of ozone transport in prior CSAPR rulemakings. The EPA is therefore returning to EGU NO_X control strategies commensurate with those determined to be necessary in the NO_X SIP Call and CAIR.

Based on the Step 3 analysis described in Section VI of this proposed rule, the EPA is proposing that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs within the borders of 25 states linked to downwind nonattainment or maintenance in 2023 (Alabama, Arkansas, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming). For 22 of those states that are also linked in 2026 (Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming), the EPA is determining that the selected EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam units of 100 MW or greater capacity (excepting circulating fluidized bed units (CFB)), new SNCR on coal steam units of less than 100 MW capacity and CFBs, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

To identify appropriate control strategies for non-EGU sources to achieve NO_X emissions reductions that would result in meaningful air quality improvements in downwind areas, the EPA developed an analytical framework to evaluate the air quality impacts of potential emissions reductions from non-EGU sources located in the linked upwind states. The EPA incorporated air quality modeling information, annual emissions, and information about potential controls to determine which industries, if subject to further control requirements, would have the greatest impact in providing air quality improvements at the downwind receptors. This evaluation was subject to a marginal cost threshold of up to $7,500 per ton, which the EPA determined based on information available to the Agency about existing control device efficiency and cost information. Additional information on the analytical framework is described in Section VI.B.2 of this proposed rule and is presented in the memorandum titled *Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026* (''Non-EGU Screening Assessment memorandum''), which is available in the docket for this proposed rulemaking. Based on the results of this assessment, the EPA identified emissions unit types in seven industries (identified in Section I.A.2 of this proposed rule) that provide opportunities for NO_X emissions reductions that result in meaningful impacts on air quality at the downwind receptors.

The EPA performed air quality analysis using the Ozone Air Quality Assessment Tool (AQAT) to determine whether the proposed emissions reductions for both EGUs and non-EGUs potentially create an ''over-control'' scenario whereby (1) the expected ozone improvements would be greater than necessary to resolve the downwind ozone pollution problem (*i.e.,* beyond what is necessary to resolve all nonattainment and maintenance problems to which an upwind state is linked) or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the NAAQS or 0.70 ppb). The EPA's over-control analysis, discussed in Section VI.D.4 of this proposed rule, shows that the proposed control stringencies for EGU and non-EGU sources do not over-control upwind states' emissions either with respect to the downwind air quality problems to which they are linked or with respect to the 1 percent of the NAAQS contribution threshold, such that over-control would trigger re-evaluation at Step 3 for any linked upwind state.

[14] *See, e.g.,* 70 FR 25162, 25205–06 (May 12, 2005).

Based on the multi-factor test applied to both EGU and non-EGU sources and our subsequent assessment of over-control, the EPA finds that the selected EGU and non-EGU control stringencies constitute the elimination of significant contribution and interference with maintenance, without over-controlling emissions, from the 26 upwind states subject to EGU and non-EGU emissions reductions requirements under the proposed rule. In order to eliminate significant contribution and interference with maintenance through the fourth step of the 4-step framework, as described in Section VII of this proposed rule, the EPA is establishing emissions budgets for EGUs within the borders of 25 states that reflect the remaining allowable emissions after the emissions reductions associated with the selected control stringency have been achieved. For the same reason, the EPA is establishing non-EGU emissions limits in 23 states that result in the elimination of significant contribution from non-EGU sources in these states. For additional details about the test and the over-control analysis, *see* the document titled, ''Ozone Transport Policy Analysis Proposed Rule TSD'' included in the docket for this rulemaking.

In this fourth step of the 4-step framework, the EPA proposes to include enforceable measures in the promulgated FIPs to achieve the required emissions reductions in each of the 26 states. Specifically, the FIPs would require covered power plants within the borders of the 25 states listed in Table I.A–1 to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program created by the Revised CSAPR Update. Affected EGUs within the borders of twelve states currently participating in the Group 3 Trading Program would remain in the program, with revised provisions beginning in the 2023 ozone season, under this proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs within the borders of eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 control period,[15] and affected EGUs within the borders of five states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Delaware, Minnesota, Nevada, Utah, and Wyoming—would enter the Group 3 trading program in the 2023 control period following the effective date of the final rule. In addition, the EPA proposes to revise other aspects of the Group 3 trading program to help maintain control stringency over time and improve emissions performance at individual units, offering a necessary measure of assurance that existing pollution controls will be operated during the ozone season, as described in Section VII of this proposed rule. This proposal does not revise the budget stringency and geography of the existing CSAPR NO_X Ozone Season Group 1 trading program. Aside from the eight states moving from the Group 2 trading program to the Group 3 trading program under the proposed rule, this proposal otherwise leaves unchanged the budget stringency of the existing CSAPR NO_X Ozone Season Group 2 trading program.

The EPA is proposing preset ozone season NO_X emissions budgets for the 2023 and 2024 ozone seasons, as explained in Section VII.B of this proposed rule and as shown in Table I.B–1.

TABLE I.B–1—PROPOSED AND ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR 2023 THROUGH 2026 CONTROL PERIODS *

State	Proposed emissions budgets for 2023 control period (tons)	Proposed emissions budgets for 2024 control period (tons)	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Alabama	6,364	6,306	6,306	6,306
Arkansas	8,889	8,889	8,889	3,923
Delaware	384	434	434	434
Illinois	7,364	7,463	7,463	6,115
Indiana	11,151	9,391	8,714	7,791
Kentucky	11,640	11,640	11,134	7,573
Louisiana	9,312	9,312	9,179	3,752
Maryland	1,187	1,187	1,187	1,189
Michigan	10,718	10,718	10,759	6,114
Minnesota	3,921	3,921	3,910	2,536
Mississippi	5,024	4,400	4,400	1,914
Missouri	11,857	11,857	10,456	7,246
Nevada	2,280	2,372	2,372	1,211
New Jersey	799	799	799	799
New York	3,763	3,763	3,763	3,238
Ohio	8,369	8,369	8,369	8,586
Oklahoma	10,265	9,573	9,393	4,275
Pennsylvania	8,855	8,855	8,855	6,819
Tennessee	4,234	4,234	4,008	4,008
Texas	38,284	38,284	36,619	21,946
Utah	14,981	15,146	15,146	2,620
Virginia	3,090	2,814	2,948	2,567
West Virginia	12,478	12,478	12,478	10,597
Wisconsin	5,963	5,057	4,198	3,473

[15] The EPA would deem participation in the Group 3 trading program by the EGUs in these eight states as also addressing the respective states' good neighbor obligations with respect to the 2008 ozone NAAQS (for all eight states), the 1997 ozone NAAQS (for all the states except Texas), and the 1979 ozone NAAQS (for Alabama, Missouri, and Tennessee) to the same extent that those obligations are currently being addressed by participation of the states' EGUs in the Group 2 trading program.

TABLE I.B–1—PROPOSED AND ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR 2023 THROUGH 2026 CONTROL PERIODS *—Continued

State	Proposed emissions budgets for 2023 control period (tons)	Proposed emissions budgets for 2024 control period (tons)	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Wyoming	9,125	8,573	8,573	4,490

* Further information on the state-level emissions budget calculations pertaining to Table I.B–1 is provided in Section VII.B.4 of this proposed rule as well as the Ozone Transport Policy Analysis Proposed Rule TSD. Further information on the proposed approach for allocating a portion of Utah's emissions budget for each control period to the existing EGU in the Uintah and Ouray Reservation within Utah's borders is provided in Section VII.B.9 of this proposed rule.

Beyond preset emissions budgets for the 2023 and 2024 control periods, the EPA also proposes to extend the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update so as to routinely set emissions budgets for each future control period (beginning in 2025) in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined (*see* Table VII.B.4.c–2 for illustrative examples of dynamic budget calculations that the EPA will publish in advance of each ozone season, effective for the 2025 control period and beyond). The stringency of the dynamic emissions budgets would simply reflect the stringency of the emissions control strategies selected in the rulemaking more consistently over time and ensure that the annual updates would eliminate emissions determined to be unlawful under the good neighbor provision. *See* Section VII.B of this proposed rule for additional discussion of EPA's proposed method for adjusting emissions budgets to ensure elimination of significant contribution from EGU sources in the linked upwind states.

As an enhancement to the structure of the trading program as originally promulgated in the Revised CSAPR Update, the EPA is also proposing to establish backstop daily emissions rates for coal steam units greater than or equal to 100 MW in covered states. Units emitting in excess of these daily rates would be subject to increased allowance surrender requirements under the trading program. The backstop daily emissions rates would work in tandem with the ozone season emissions budgets to offer downwind stakeholders a necessary measure of assurance that they will be protected on a daily basis during the ozone season by continuous operation of installed pollution controls. The EPA's experience with the CSAPR trading programs has revealed instances where EGUs have reduced their SCRs' performance on a given day, or across the entire ozone seasons in some cases, including high ozone days.[16] In addition to maintaining a mass-based seasonal requirement, the EPA proposes to require controls while maintaining as much compliance flexibility as possible through a unit-level emission rate designed to ensure that controls operate continuously and that required reductions occur on the highest ozone days. These trading program improvements also promote consistent emissions control performance across the power sector, which protects communities living in downwind ozone nonattainment areas from exceedances of the NAAQS that might otherwise occur.

The EPA proposes to include enforceable emissions standards that will apply during the ozone season (annually from May to September) for seven non-EGU industries in the promulgated FIPs to achieve the required emissions reductions in 23 states with remaining interstate transport obligations for the 2015 ozone NAAQS in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. These requirements would apply to all existing emissions units and to any future emissions units constructed in the covered states after promulgation of the final rule. Thus, the emissions limits for non-EGU sources and associated compliance requirements would apply in all 23 states listed in this paragraph, even if certain of these states do not currently have existing emissions units within a particular industry.

Based on our evaluation of the time required to install controls at the types of non-EGU sources covered by this proposed rule, the EPA has identified the 2026 ozone season as the earliest compliance date possible for non-EGU emissions reductions. The EPA is therefore proposing to include non-EGU emissions reductions beginning in 2026. For sources located in the 23 states listed in the previous paragraph, The EPA proposes to require the emissions limits listed in Table I.B–2 for

[16] *See* 86 FR 23090. The EPA highlighted the Miami Fort Unit 7 (possessing a SCR) more than tripled its ozone-season NO_X emission rate between 2017 and 2019.

reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; the emissions limits listed in Table I.B–3 for kilns in Cement and Cement Product Manufacturing; the emissions limits listed in Table I.B–4 for boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; the emissions limits listed in Table I.B–5 for furnaces in Glass and Glass Product Manufacturing; and the emissions limits listed in Table I.B–6 for high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

TABLE I.B–2—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	Proposed NO_X emissions limit
Natural Gas Fired Four Stroke Rich Burn.	1.0 g/hp-hr.
Natural Gas Fired Four Stroke Lean Burn.	1.5 g/hp-hr.
Natural Gas Fired Two Stroke Lean Burn.	3.0 g/hp-hr.

TABLE I.B–3—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	Proposed NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

The EPA is also proposing a source cap limit expressed in ton per day (tpd) of NO_X for each individual cement plant according to the following equation.[17]

$$CAP2015\,Ozone\,Transport = \frac{(KW\ x\ NW) + (KD\ x\ ND)}{(2000\frac{pounds}{ton}\ x\ 365\frac{days}{year})}$$

Where:

CAP2015 Ozone Transport = total allowable NO_X emissions from all cement kilns located at one cement plant, in tons per day, on a 30-operating day rolling average basis;

KD = 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns;

KW = 3.4 pounds NO_X per ton of clinker for long wet kilns;

ND = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all dry preheater-precalciner or precalciner kilns located at one cement plant; and

NW = the average annual production in tons of clinker plus one standard deviation for the 3 most recent calendar years from all long wet kilns located at one cement plant.

An affected cement plant will need to comply with both the source cap limit and the specific NO_X emissions limits assigned to its individual kiln type(s). Refer to Section VII.C.2 of this proposed rule for additional information concerning the application of the source cap limit to this industry source group.

TABLE I.B–4—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS

Emissions unit	Proposed NO_X emissions standard or requirement (lbs/hour or lb/mmBtu)
Blast Furnace	0.03 lb/mmBtu.
Basic Oxygen Furnace	0.07 lb/ton.
Electric Arc Furnace	0.15 lb/ton steel.
Ladle/tundish Preheaters	0.06 lb/mmBtu.
Reheat furnace	0.05 lb/mmBtu.
Annealing Furnace	0.06 lb/mmBtu.
Vacuum Degasser	0.03 lb/mmBtu.
Ladle Metallurgy Furnace	0.1 lb/ton.
Taconite production kilns	Work practice standard to install low NO_X technology/burners, test and set.
Coke ovens (charging and coking)	0.6 lb/ton of coal charged.
Coke ovens (pushing)	0.015 lb/ton of coal pushed.
Boilers—Coal	0.20 lb/mmBtu.
Boilers—Residual oil	0.20 lb/mmBtu.
Boilers—Distillate oil	0.12 lb/mmBtu.
Boilers—Natural gas	0.08 lb/mmBtu.

[17] Based on source cap equation at 30 TAC § 117.3123(b); January 14, 2009 (74 FR 1927), Docket ID No. EPA–R06–OAR–2007–1147, also *see https://wayback.archive-it.org/414/20210527223433/https://www.tceq.texas.gov/assets/public/legal/rules/rules/pdflib/117e.pdf.*

TABLE IV.B–5—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	Proposed NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	9.2

TABLE I.B–6—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR HIGH-EMITTING EQUIPMENT AND LARGE BOILERS IN BASIC CHEMICAL MANUFACTURING, PETROLEUM AND COAL PRODUCTS MANUFACTURING, AND PULP, PAPER, AND PAPERBOARD MILLS

Unit type	Emissions limit (lbs NO_X/mmBtu)
Coal	0.20
Residual oil	0.20
Distillate oil	0.12
Natural gas	0.08

Refer to Section VII.C of this proposed rule for applicability criteria, compliance assurance requirements, and the EPA's rationale in proposing these emissions limits for each of the non-EGU industries covered by the proposed rule. In addition, the EPA requests comment on several topics regarding the implementation of emissions limits for non-EGU sources that are proposed in this rulemaking, including controls on emissions units and control installation timing. *See* Section VI.D.2.a of this proposed rule for a list of detailed questions on which the Agency is soliciting public comment.

The remainder of this preamble is organized as follows: Section III of this proposed rule outlines general applicability criteria for the proposed rule and describes the EPA's legal authority for this proposed rule, the relationship of the proposed rule to previous interstate ozone transport rulemakings, and the incremental costs and benefits of the proposed rule; Section IV of this proposed rule describes the human health and environmental challenges posed by interstate transport contributions to ozone air quality problems, as well as EPA's overall approach for addressing interstate transport for the 2015 ozone NAAQS in this proposed rule; Section V of this proposed rule describes the Agency's analyses of air quality data to inform this proposed rulemaking, including descriptions of the air quality modeling platform and emissions inventories used in the proposed rule, as well as EPA's methods for identifying downwind air quality problems and upwind states' ozone transport contributions to downwind states; Section VI of this proposed rule describes EPA's approach to quantifying upwind states' obligations in the form of EGU NO_X control stringencies and non-EGU emissions limits; Section VII of this proposed rule describes key elements of the implementation schedule for EGU and non-EGU emissions reductions requirements, including details regarding the revised aspects of the CSAPR NO_X Group 3 trading program and compliance deadlines, as well as regulatory requirements and compliance deadlines for non-EGU sources; Section VIII of this proposed rule discusses the environmental justice considerations of the proposed rule; Section IX of this proposed rule describes the expected costs, benefits, and other impacts of this proposed rule; Section X of this proposed rule provides a summary of proposed changes to the existing regulatory text; and Section XI of this proposed rule discusses the statutory and executive orders affecting this proposed rulemaking.

C. Costs and Benefits

A summary of the key results of the cost-benefit analysis that was prepared for this proposed rule is presented in Table I.C–1. Table I.C–1 presents estimates of the present values (PV) and equivalent annualized values (EAV), calculated using discount rates of 3 and 7 percent as directed by OMB's Circular A–4, of the health benefits, compliance costs, and net benefits of the proposed rule, in 2016 dollars, discounted to 2022. The estimated monetized net benefits are the estimated monetized benefits minus the estimated monetized costs of the proposed rule. These results present an incomplete overview of the effects of the proposal, because important categories of benefits—including benefits from reducing climate pollution, other types of air pollutants, and water pollution—were not monetized and are therefore not reflected in the cost-benefit tables. We anticipate that taking non-monetized effects into account would show the proposal to be more net beneficial than this table reflects.

TABLE I.C–1—ESTIMATED MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE, 2023 THROUGH 2042

[Millions 2016$, discounted to 2022][a]

	3% Discount rate	7% Discount rate
Present Value:		
Benefits[b]	250,000	150,000
Compliance Costs[c]	22,000	14,000
Net Benefits	220,000	130,000
Equivalent Annualized Value:		
Benefits	17,000	14,000
Compliance Costs	1,500	1,300

TABLE I.C–1—ESTIMATED MONETIZED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE, 2023 THROUGH 2042—Continued

[Millions 2016$, discounted to 2022] [a]

	3% Discount rate	7% Discount rate
Net Benefits	15,000	12,000

[a] Rows may not appear to add correctly due to rounding.

[b] The annualized present value of costs and benefits are calculated over a 20-year period from 2023 to 2042. Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at real discount rates of 3 and 7 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden*, No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[c] The costs presented in this table are consistent with the costs presented in Chapter 4 of the RIA. To estimate these annualized costs, EPA uses a conventional and widely accepted approach that applies a capital recovery factor (CRF) multiplier to capital investments and adds that to the annual incremental operating expenses. Costs were calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

As shown in Table I.C–1, the PV of the benefits, associated with reductions in $PM_{2.5}$ and ozone concentrations, of this proposed rule, discounted at a 3-percent discount rate, is estimated to be about $250,000 million, with an EAV of about $17,000 million. At a 7-percent discount rate, the PV of the benefits is estimated to be $150,000 million, with an EAV of about $14,000 million. The PV of the compliance costs, discounted at a 3-percent rate, is estimated to be about $22,000 million, with an EAV of about $1,500 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $14,000 million, with an EAV of about $1,300 million.

II. Public Participation

A. Written Comments

Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2021–0668 at *https://www.regulations.gov* (our preferred method), or the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

Due to public health concerns related to COVID–19, the EPA Docket Center and Reading Room are open to the public by appointment only. Our Docket Center staff also continues to provide remote customer service via email, phone, and webform. Hand deliveries or couriers will be received by scheduled appointment only. For further information and updates on EPA Docket Center services, please visit us online at *https://www.epa.gov/dockets.*

The EPA continues to carefully and continuously monitor information from the Centers for Disease Control and Prevention (CDC), local area health departments, and our Federal partners so that we can respond rapidly as conditions change regarding COVID–19.

B. Submitting Confidential Business Information

Do not submit information containing CBI to the EPA through *https://www.regulations.gov.* Clearly mark the part or all of the information that you claim to be CBI. For CBI information on any digital storage media that you mail to the EPA, mark the outside of the digital storage media as CBI and then identify electronically within the digital storage media the specific information that is claimed as CBI. In addition to one complete version of the comments that includes information claimed as CBI, you must submit a copy of the comments that does not contain the information claimed as CBI directly to the public docket through the procedures outlined in *Instructions* earlier. If you submit any digital storage media that does not contain CBI, mark the outside of the digital storage media clearly that it does not contain CBI. Information not marked as CBI will be included in the public docket and the EPA's electronic public docket without prior notice. Information marked as CBI will not be disclosed except in accordance with procedures set forth in 40 Code of Federal Regulations (CFR) part 2. Our preferred method to receive CBI is for it to be transmitted to electronically using email attachments, File Transfer Protocol (FTP), or other online file sharing services (*e.g.,* Dropbox, OneDrive, Google Drive). Electronic submissions must be transmitted directly to the OAQPS CBI Office using the email address, *oaqpscbi@epa.gov,* and should include clear CBI markings as described above. If assistance is needed with submitting large electronic files that exceed the file size limit for email attachments, and if you do not have your own file sharing service, please email *oaqpscbi@epa.gov* to request a file transfer link. If sending CBI information through the postal service, please send it to the following address: OAQPS Document Control Officer (C404–02), OAQPS, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention Docket ID No. EPA–HQ–OAR–2021–0668. The mailed CBI material should be double wrapped and clearly marked. Any CBI markings should not show through the outer envelope.

C. Participation in Virtual Public Hearing

Please note that because of current CDC recommendations, as well as state and local orders for social distancing to limit the spread of COVID–19, the EPA cannot hold in-person public meetings at this time.

The EPA will begin pre-registering speakers for the hearing no later than 1 business day after publication of this document in the **Federal Register**. To register to speak at the virtual hearing, please use the online registration form available at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.* The last day to pre-register to speak at the hearing will be April 21, 2022. The EPA will post a general agenda for the hearing that will list pre-registered speakers in approximate order at: *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.*

The virtual public hearing will be held on via teleconference on April 21, 2022. The virtual public hearing will convene at 10:00 a.m. Eastern Time (ET) and will conclude at 7:00 p.m. ET. The EPA may close a session 15 minutes after the last pre-registered speaker has testified if there are no additional speakers. For information or questions about the public hearing, please contact Ms. Holly DeJong at *Dejong.holly@epa.gov.* The EPA will announce further details at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.*

The EPA will make every effort to follow the schedule as closely as possible on the day of the hearing; however, please plan for the hearings to run either ahead of schedule or behind schedule.

Each commenter will have 5 minutes to provide oral testimony. The EPA encourages commenters to provide the EPA with a copy of their oral testimony electronically (via email) by emailing it to *Dejong.holly@epa.gov.* The EPA also recommends submitting the text of your oral comments as written comments to the rulemaking docket.

The EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Written statements and supporting information submitted during the comment period will be considered with the same weight as oral comments and supporting information presented at the public hearing.

Please note that any updates made to any aspect of the hearing will be posted online at *https://www.epa.gov/csapr/csapr-2015-ozone-naaqs.* While the EPA expects the hearing to go forward as set forth above, please monitor our website or contact Ms. Holly DeJong at *Dejong.holly@epa.gov* to determine if there are any updates. The EPA does not intend to publish a document in the **Federal Register** announcing updates.

If you require the services of a translator or special accommodations such as audio description, please pre-register for the hearing and describe your needs by April 18, 2022. EPA may not be able to arrange accommodations without advanced notice.

III. General Information

A. Does this action apply to me?

This proposed rule affects EGU and non-EGU sources, and regulates the groups identified in Table III.A–1.

TABLE III.A–1—REGULATED GROUPS

Industry group	NAICS
Fossil fuel-fired electric power generation	221112
Pipeline Transportation of Natural Gas	4862
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this proposed rule. This table lists the types of entities that the EPA is now aware could potentially be regulated by this proposed rule. Other types of entities not listed in the table could also be regulated. For example, the EPA is requesting comment in Section VI.B.3 of this proposed rule on potential control strategies for sources outside of the categories listed in the Table III.A.1, such as municipal waste combustors (MWCs). To determine whether your EGU entity is proposed to be regulated by this proposed rule, you should carefully examine the applicability criteria found in 40 CFR 97.1004, which the EPA is not proposing to alter in this proposed rule. If you have questions regarding the applicability of this proposed rule to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What action is the Agency taking?

The EPA evaluated whether interstate ozone transport emissions from upwind states are significantly contributing to nonattainment, or interfering with maintenance, of the 2015 ozone NAAQS in any downwind state using the same 4-step interstate transport framework that was developed in previous ozone transport rulemakings. The EPA is proposing to find that emissions reductions are required from EGU and non-EGU sources in a total of 26 upwind states to eliminate significant contribution to downwind air quality problems for the 2015 ozone standard under the interstate transport provision of the CAA. The EPA will ensure that these NO_X emissions reductions are achieved by issuing proposed FIP requirements for 26 states: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

The EPA is proposing to revise the existing CSAPR Group 3 Trading Program to include additional states beginning in the 2023 ozone season. EGUs in five states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Delaware, Minnesota, Nevada, Utah, and Wyoming—would be added to the CSAPR Group 3 Trading Program under this proposed rule. EGUs in twelve states currently participating in the Group 3 Trading Program would remain in the program under this proposed rule: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. EGUs in eight states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin) will transition from the CSAPR Group 2 Trading Program to the CSAPR Group 3 Trading Program under this proposed rule beginning in the 2023 ozone season. The EPA proposes to establish control stringency levels reflecting installation of state-of-the-art combustion controls on certain covered EGU sources in emissions budgets beginning in the 2024 ozone season. The EPA proposes to establish control stringency levels reflecting installation of new SCR or SNCR controls on certain covered EGU sources in emissions budgets beginning in the 2026 ozone season.

As a complement to the ozone season emissions budgets, the EPA is also proposing to establish backstop daily emissions rates of 0.14 lb/mmBtu for coal-fired steam units greater than or equal to 100 MW in covered states. The backstop emissions rates will first apply in 2024 for coal-fired steam sources with existing SCRs, and in 2027 for those currently without SCRs.

In this proposed rule, the EPA is proposing to require emissions limitations for non-EGU sources in 23 states: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and

Wyoming. In these states, EPA is proposing to require emissions limitations for the following unit types in non-EGU industries: Furnaces in Glass and Glass Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; kilns in Cement and Cement Product Manufacturing; reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mill. See Table III.A–1 for a list of NAICS codes for each entity included for regulation under this proposed rule.

The proposed rule would reduce the transport of ozone precursor emissions to downwind areas, which is protective of human health and the environment because acute and chronic exposure to ozone are both associated with negative health impacts. Ozone exposure is also associated with negative effects on ecosystems. Additional information on the human health and environmental benefits from the air quality issues addressed by this proposed rule are included in Section IV of this proposed rule.

C. What is the Agency's legal authority for taking this action?

1. Statutory Authority

The statutory authority for this proposed rule is provided by the CAA as amended (42 U.S.C. 7401 *et seq.*). Specifically, sections 110 and 301 of the CAA provide the primary statutory underpinnings for this proposed rule. The most relevant portions of CAA section 110 are subsections 110(a)(1), 110(a)(2) (including 110(a)(2)(D)(i)(I)), 110(c)(1), and 110(k)(6)).

CAA section 110(a)(1) provides that states must make SIP submissions ''within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof),'' and that these SIP submissions are to provide for the ''implementation, maintenance, and enforcement'' of such NAAQS.[18] The statute directly imposes on states the duty to make these SIP submissions, and the requirement to make the submissions is not conditioned upon the EPA taking any action other than promulgating a new or revised NAAQS.[19]

[18] 42 U.S.C. 7410(a)(1).

[19] *See EPA* v. *EME Homer City Generation, L.P.*, 572 U.S. 489, 509–10 (2014).

The EPA has historically referred to SIP submissions made for the purpose of satisfying the applicable requirements of CAA sections 110(a)(1) and 110(a)(2) as ''infrastructure SIP'' or ''iSIP'' submissions. CAA section 110(a)(1) addresses the timing and general requirements for iSIP submissions, and CAA section 110(a)(2) provides more details concerning the required content of these submissions.[20] It includes a list of specific elements that ''[e]ach such plan'' must address.[21]

CAA section 110(c)(1) requires the Administrator to promulgate a FIP at any time within two years after the Administrator: (1) Finds that a state has failed to make a required SIP submission; (2) finds a SIP submission to be incomplete pursuant to CAA section 110(k)(1)(C); or (3) disapproves a SIP submission. This obligation applies unless the state corrects the deficiency through a SIP revision that the Administrator approves before the FIP is promulgated.[22]

CAA section 110(a)(2)(D)(i)(I), also known as the ''good neighbor'' provision, provides the primary basis for this proposed rule.[23] It requires that each state SIP include provisions sufficient to ''prohibit[ ], consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS].'' [24] The EPA often refers to the emissions reduction requirements under this provision as ''good neighbor obligations'' and submissions addressing these requirements as ''good neighbor SIPs.''

Once EPA promulgates a NAAQS, the EPA must designate areas as being in ''attainment'' or ''nonattainment'' of the NAAQS, or ''unclassifiable.'' CAA section 107(d).[25] For ozone, nonattainment is further split into five classifications based on the severity of the violation—Marginal, Moderate, Serious, Severe, or Extreme. Higher classifications provide states with progressively more time to attain while

[20] 42 U.S.C. 7410(a)(2).

[21] EPA's general approach to infrastructure SIP submissions is explained in greater detail in individual notices acting or proposing to act on state infrastructure SIP submissions and in guidance. *See, e.g.,* Memorandum from Stephen D. Page on Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2) (September 13, 2013).

[22] 42 U.S.C. 7410(c)(1).

[23] 42 U.S.C. 7410(a)(2)(D)(i)(I).

[24] *Id.*

[25] 42 U.S.C. 7407(d).

imposing progressively more stringent control requirements. *See* CAA sections 181, 182.[26] In general, states with nonattainment areas classified as Moderate or higher must submit plans to EPA to bring these areas into attainment according to the statutory schedule. CAA section 182.[27] If an area fails to attain the NAAQS by the attainment date associated with its classification, it is ''bumped up'' to the next classification. CAA section 181(b).[28]

Section 301(a)(1) of the CAA gives the Administrator the general authority to prescribe such regulations as are necessary to carry out functions under the Act.[29] Pursuant to this section, EPA has authority to clarify the applicability of CAA requirements and undertake other rulemaking action as necessary to implement CAA requirements. CAA section 301 affords the Agency any additional authority that may be needed in order to make certain other changes to its regulations under 40 CFR parts 52, 75, 78, and 97, in order to effectuate the purposes of the Act. Such changes are discussed in Section X of this proposed rule.

Section 110(k)(6) of the CAA gives the Administrator authority, without any further submission from a state, to revise certain prior actions, including actions to approve SIPs, upon determining that those actions were in error.[30] The EPA proposes to make an error correction under CAA section 110(k)(6) with respect to its prior approval of the 2015 ozone transport SIP submission from the State of Delaware. This is further discussed in Section IV.C.1 of the proposed rule.

Tribes are not required to submit state implementation plans. However, as explained in EPA's regulations outlining Tribal Clean Air Act authority, the EPA is authorized to promulgate FIPs for Indian country as necessary or appropriate to protect air quality if a tribe does not submit, and obtain EPA approval of, an implementation plan. *See* 40 CFR 49.11(a); *see also* CAA section 301(d)(4).[31] In this proposed rule, the EPA proposes an ''appropriate or necessary'' finding under CAA section 301(d) and proposes tribal FIP(s) as necessary to implement the relevant requirements. This is further discussed in Section IV.C.2 of the proposed rule.

[26] 42 U.S.C. 7511, 7511a.

[27] 42 U.S.C. 7511a.

[28] 42 U.S.C. 7511(b).

[29] 42 U.S.C. 7601(a)(1).

[30] 42 U.S.C. 7410(k)(6).

[31] 42 U.S.C. 7601(d)(4).

D. What actions has EPA previously issued to address regional ozone transport?

The EPA has issued several major rules interpreting and clarifying the requirements of CAA section 110(a)(2)(D)(i)(I) with respect to the regional transport of ozone. These rules, and the associated court decisions addressing these rules, summarized here, provide important direction regarding the requirements of CAA section 110(a)(2)(D)(i)(I).

The ''NO_X SIP Call,'' promulgated in 1998, addressed the good neighbor provision for the 1979 1-hour ozone NAAQS.[32] The rule required 22 states and the District of Columbia to amend their SIPs to reduce NO_X emissions that contribute to ozone nonattainment in downwind states. The EPA set ozone season NO_X budgets for each state, and the states were given the option to participate in a regional allowance trading program, known as the NO_X Budget Trading Program.[33] The D.C. Circuit largely upheld the NO_X SIP Call in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), *cert. denied,* 532 U.S. 904 (2001).

EPA's next rule addressing the good neighbor provision, the Clean Air Interstate Rule (CAIR), was promulgated in 2005 and addressed both the 1997 fine particulate matter ($PM_{2.5}$) NAAQS and 1997 ozone NAAQS.[34] CAIR required SIP revisions in 28 states and the District of Columbia to reduce emissions of sulfur dioxide (SO_2) or NO_X—important precursors of regionally transported $PM_{2.5}$ (SO_2 and annual NO_X) and ozone (summer-time NO_X). As in the NO_X SIP Call, states were given the option to participate in regional trading programs to achieve the reductions. When the EPA promulgated the final CAIR in 2005, the EPA also issued findings that states nationwide had failed to submit SIPs to address the requirements of CAA section 110(a)(2)(D)(i) with respect to the 1997 $PM_{2.5}$ and 1997 ozone NAAQS.[35] On March 15, 2006, the EPA promulgated FIPs to implement the emissions reductions required by CAIR.[36] CAIR was remanded to EPA by the D.C. Circuit in *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *modified on reh'g,* 550 F.3d 1176. For more information on the legal issues underlying CAIR and the D.C. Circuit's holding in *North Carolina,* refer to the preamble of the CSAPR rule.[37]

In 2011, the EPA promulgated CSAPR to address the issues raised by the remand of CAIR. CSAPR addressed the two NAAQS at issue in CAIR and additionally addressed the good neighbor provision for the 2006 $PM_{2.5}$ NAAQS.[38] CSAPR required 28 states to reduce SO_2 emissions, annual NO_X emissions, or ozone season NO_X emissions that significantly contribute to other states' nonattainment or interfere with other states' abilities to maintain these air quality standards.[39] To align implementation with the applicable attainment deadlines, the EPA promulgated FIPs for each of the 28 states covered by CSAPR. The FIPs require EGUs in the covered states to participate in regional trading programs to achieve the necessary emissions reductions. Each state can submit a good neighbor SIP at any time that, if approved by EPA, would replace the CSAPR FIP for that state.

CSAPR was the subject of an adverse decision by the D.C. Circuit in August 2012.[40] However, this decision was reversed in April 2014 by the Supreme Court, which largely upheld the rule, including EPA's approach to addressing interstate transport in CSAPR. *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014) (*EME Homer City I*). The rule was remanded to the D.C. Circuit to consider claims not addressed by the Supreme Court. *Id.* In July 2015 the D.C. Circuit generally affirmed EPA's interpretation of various statutory provisions and EPA's technical decisions. *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118 (2015) (*EME Homer City II*). However, the court remanded the rule without vacatur for reconsideration of EPA's emissions budgets for certain states, which the court found may have over-controlled those states' emissions with respect to the downwind air quality problems to which the states were linked. *Id.* at 129–30, 138. For more information on the legal issues associated with CSAPR and the Supreme Court's and D.C. Circuit's decisions in the *EME Homer City* litigation, refer to the preamble of the CSAPR Update.[41]

In 2016, the EPA promulgated the CSAPR Update to address interstate transport of ozone pollution with respect to the 2008 ozone NAAQS.[42] The final rule updated the CSAPR ozone season NO_X emissions budgets for 22 states to achieve cost-effective and immediately feasible NO_X emissions reductions from EGUs within those states.[43] The EPA aligned the analysis and implementation of the CSAPR Update with the 2017 ozone season in order to assist downwind states with timely attainment of the 2008 ozone NAAQS.[44] The CSAPR Update implemented the budgets through FIPs requiring sources to participate in a revised CSAPR NO_X ozone season trading program beginning with the 2017 ozone season. As under CSAPR, each state could submit a good neighbor SIP at any time that, if approved by the EPA, would replace the CSAPR Update FIP for that state. The final CSAPR Update also addressed the remand by the D.C. Circuit of certain states' CSAPR phase 2 ozone season NO_X emissions budgets in *EME Homer City II.*

In December 2018, the EPA promulgated the CSAPR ''Close-Out,'' which determined that no further enforceable reductions in emissions of NO_X were required with respect to the

[32] *Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone,* 63 FR 57356 (Oct. 27, 1998). As originally promulgated, the NO_X SIP Call also addressed good neighbor obligations under the 1997 8-hour ozone NAAQS, but EPA subsequently stayed and later rescinded the rule's provisions with respect to that standard. *See* 84 FR 8422 (March 8, 2019).

[33] ''Allowance Trading,'' sometimes referred to as ''cap and trade,'' is an approach to reducing pollution that has been used successfully to protect human health and the environment. The design elements of EPA's most recent trading programs are discussed in Section VII.B.1.a of this proposed rule.

[34] *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the* NO_X *SIP Call,* 70 FR 25162 (May 12, 2005).

[35] 70 FR 21147 (April 25, 2005).

[36] 71 FR 25328 (April 28, 2006).

[37] *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals,* 76 FR 48208, 48217 (August 8, 2011).

[38] 76 FR 48208.

[39] CSAPR was revised by several rulemakings after its initial promulgation in order to revise certain states' budgets and to promulgate FIPs for five additional states addressing the good neighbor obligation for the 1997 ozone NAAQS. *See* 76 FR 80760 (December 27, 2011); 77 FR 10324 (February 21, 2012); 77 FR 34830 (June 12, 2012).

[40] On August 21, 2012, the D.C. Circuit issued a decision in *EME Homer City Generation, L.P.* v. *EPA,* 696 F.3d 7 (D.C. Cir. 2012), vacating CSAPR. The EPA sought review with the D.C. Circuit *en banc* and the D.C. Circuit declined to consider EPA's appeal *en banc. EME Homer City Generation, L.P.* v. *EPA,* No. 11–1302 (D.C. Cir. January 24, 2013), ECF No. 1417012 (denying EPA's motion for rehearing en banc).

[41] *Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 81 FR 74504, 74511 (October 26, 2016).

[42] 81 FR 74504.

[43] One state, Kansas, was made newly subject to ozone season NO_X requirements by the CSAPR Update. All other CSAPR Update states were already subject to ozone season NO_X requirements under CSAPR.

[44] 81 FR 74516. EPA's final 2008 Ozone NAAQS SIP Requirements Rule, 80 FR 12264, 12268 (March 6, 2015), revised the attainment deadline for ozone nonattainment areas designated as Moderate to July 20, 2018. *See* 40 CFR 51.1103. In order to demonstrate attainment by this deadline, states were required to rely on design values calculated using ozone season data from 2015 through 2017, since the July 20, 2018, deadline did not afford enough time for measured data of the full 2018 ozone season.

2008 ozone NAAQS for 20 of the 22 eastern states covered by the CSAPR Update, and reflected that determination in revisions to the existing state-specific sections of the CSAPR Update regulations for those states.[45]

The CSAPR Update and the CSAPR Close-Out were both subject to legal challenges in the D.C. Circuit. *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019) (*Wisconsin*); *New York* v. *EPA,* 781 Fed. App'x 4 (D.C. Cir. 2019) (*New York*). In September 2019, the D.C. Circuit upheld the CSAPR Update in virtually all respects but remanded the rule because it was partial in nature and did not fully eliminate upwind states' significant contribution to nonattainment or interference with maintenance of the 2008 ozone NAAQS by ''the relevant downwind attainment deadlines'' in the CAA. *Wisconsin,* 938 F.3d at 313–15. In October 2019, the D.C. Circuit vacated the CSAPR Close-Out on the same grounds that it remanded the CSAPR Update in *Wisconsin,* specifically that the Close-Out rule did not address good neighbor obligations by ''the next applicable attainment date'' of downwind states. *New York,* 781 Fed. App'x at 7.[46]

In response to the *Wisconsin* remand of the CSAPR Update and the *New York* vacatur of the CSAPR Close-Out, the EPA promulgated the Revised CSAPR Update on April 30, 2021.[47] The Revised CSAPR Update found that the CSAPR Update was a full remedy for nine of the covered states. For the 12 remaining states, the EPA found that their projected 2021 ozone season NO_X emissions significantly contribute to downwind states' nonattainment or maintenance problems. The EPA issued new or amended FIPs for these 12 states and required implementation of revised emissions budgets for EGUs beginning with the 2021 ozone season. Based on EPA's assessment of remaining air quality issues and additional emissions control strategies for EGUs and emissions sources in other industry sectors (non-EGUs), the EPA determined that the NO_X emissions reductions achieved by the Revised CSAPR Update fully eliminated these states' significant contributions to downwind air quality problems for the 2008 ozone NAAQS. As under the CSAPR and the CSAPR Update, each state can submit a good neighbor SIP at any time that, if approved by EPA, would replace the Revised CSAPR Update FIP for that state.[48]

IV. Air Quality Issues Addressed and Overall Approach for the Proposed Rule

A. The Interstate Ozone Transport Air Quality Challenge

1. Nature of Ozone and the Ozone NAAQS

Ground-level ozone is not emitted directly into the air but is created by chemical reactions between NO_X and volatile organic compounds (VOCs) in the presence of sunlight. Emissions from electric utilities and industrial facilities, motor vehicles, gasoline vapors, and chemical solvents are some of the major sources of NO_X and VOCs.

Because ground-level ozone formation increases with temperature and sunlight, ozone levels are generally higher during the summer months. Increased temperature also increases emissions of volatile man-made and biogenic organics and can also indirectly increase NO_X emissions (*e.g.,* increased electricity generation for air conditioning).

On October 1, 2015, the EPA strengthened the primary and secondary ozone standards to 70 ppb as an 8-hour level.[49] Specifically, the standards require that the 3-year average of the fourth highest 24-hour maximum 8-hour average ozone concentration may not exceed 70 ppb as a truncated value (*i.e.,* digits to right of decimal removed).[50] In general, areas that exceed the ozone standard are designated as nonattainment areas, pursuant to the designations process under CAA section 107, and are subject to heightened planning requirements depending on the degree of severity of their nonattainment classification, *see* CAA sections 181, 182.

In the process of setting the 2015 ozone NAAQS, the EPA noted that the conditions conducive to the formation of ozone (*i.e.,* seasonally-dependent factors such as ambient temperature, strength of solar insolation, and length of day) differ by location, and that the Agency believes it is important that ozone monitors operate during all periods when there is a reasonable possibility of ambient levels approaching the level of the NAAQS. At that time, the EPA stated that ambient ozone concentrations in many areas could approach or exceed the level of the NAAQS, more frequently and during more months of the year compared with the historical ozone season monitoring lengths. Consequently, the EPA extended the ozone monitoring season for many locations. *See* 80 FR 65416 for more details.

Furthermore, the EPA stated that in addition to being affected by changing emissions, future ozone concentrations may also be affected by climate change. Modeling studies in the EPA's Interim Assessment (U.S. EPA, 2009a) that are cited in support of the 2009 Endangerment Finding under CAA section 202(a) (74 FR 66496, Dec. 15, 2009) as well as a recent assessment of potential climate change impacts (Fann et al., 2015) project that climate change may lead to future increases in summer ozone concentrations across the contiguous U.S.[51] (80 FR 65300). The increase in ozone results from changes in local weather conditions, including temperature and atmospheric circulation patterns, as well as changes in ozone precursor emissions that are influenced by meteorology (Nolte et al., 2018). While the projected impact may not be uniform, climate change has the potential to increase average summertime ozone relative to a future without climate change.[52] [53] [54] Climate

[45] *Determination Regarding Good Neighbor Obligations for the 2008 Ozone National Ambient Air Quality Standard,* 83 FR 65878, 65882 (Dec. 21, 2018). After promulgating the CSAPR Update and before promulgating the CSAPR Close-Out, the EPA approved a SIP from Kentucky resolving the Commonwealth's good neighbor obligations for the 2008 ozone NAAQS. 83 FR 33730 (July 17, 2018). In the Revised CSAPR Update, the EPA made an error correction under CAA section 110(k)(6) to convert this approval to a disapproval, because the Kentucky approval relied on the same analysis which the D.C. Circuit determined to be unlawful in the CSAPR Close-Out.

[46] Subsequently, the D.C. Circuit made clear in a decision reviewing EPA's denial of a petition under CAA section 126 that the holding in *Wisconsin* regarding alignment with downwind area's attainment schedules applies with equal force to the Marginal area attainment date established under CAA section 181(a). *See Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[47] *Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS,* 86 FR 23054 (April 30, 2021).

[48] The Revised CSAPR Update is currently subject to a petition for judicial review pending in the D.C. Circuit Court of Appeals, *Midwest Ozone Group* v. *EPA,* No. 21–1146 (D.C. Cir. June 25, 2021).

[49] 80 FR 65291.

[50] 40 CFR part 50, Appendix P to part 50

[51] These modeling studies are based on coupled global climate and regional air quality models and are designed to assess the sensitivity of U.S. air quality to climate change. A wide range of future climate scenarios and future years have been modeled and there can be variations in the expected response in U.S. O^3 by scenario and across models and years, within the overall signal of higher summer O^3 concentrations in a warmer climate.

[52] Fann NL, Nolte CG, Sarofim MC, Martinich J, Nassikas NJ. Associations Between Simulated Future Changes in Climate, Air Quality, and Human Health. JAMA Netw Open. 2021;4(1):e2032064. doi: 10.1001/jamanetworkopen.2020.32064.

[53] Christopher G Nolte, Tanya L Spero, Jared H Bowden, Marcus C Sarofim, Jeremy Martinich, Megan S Mallard. Regional temperature-ozone relationships across the U.S. under multiple climate and emissions scenarios. J Air Waste Manag Assoc. 2021 Oct;71(10):1251–1264. doi: 10.1080/10962247.2021.1970048.

change has the potential to offset some of the improvements in ozone air quality, and therefore some of the improvements in public health, that are expected from reductions in emissions of ozone precursors (80 FR 65300).

2. Ozone Transport

Studies have established that ozone formation, atmospheric residence, and transport occur on a regional scale (*i.e.,* thousands of kilometers) over much of the U.S.[55] While substantial progress has been made in reducing ozone in many areas, the interstate transport of ozone precursor emissions remains an important contributor to peak ozone concentrations and high-ozone days during the summer ozone season.

The EPA has previously concluded in the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update that a regional NO_X control strategy would be effective in reducing regional-scale transport of ozone precursor emissions. NO_X emissions can be transported downwind as NO_X or as ozone after transformation in the atmosphere. In any given location, ozone pollution levels are impacted by a combination of background ozone concentration, local emissions, and emissions from upwind sources resulting from ozone transport. Downwind states' ability to meet health-based air quality standards such as the NAAQS is challenged by the transport of ozone pollution across state borders. For example, ozone assessments conducted for the October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone continue to show the importance of NO_X emissions for ozone transport. This analysis is included in the docket for this proposal.

Further, studies have found that EGU NO_X emissions reductions can be effective in reducing individual 8-hour peak ozone concentrations and in reducing 8-hour peak ozone concentrations averaged across the ozone season. For example, a study that evaluates the effectiveness on ozone concentrations of EGU NO_X reductions achieved under the NO_X Budget Trading Program (*i.e.,* the NO_X SIP Call) shows that regulating NO_X emissions in that program was highly effective in reducing ozone concentrations during the ozone season.[56]

Previous regional ozone transport efforts, including the NO_X SIP Call, CAIR, CSAPR, the CSAPR Update, and the Revised CSAPR Update, required ozone season NO_X reductions from EGU sources to address interstate transport of ozone. Together with NO_X, EPA has also identified VOCs as a precursor in forming ground-level ozone. Ozone formation chemistry can be ''NO_X-limited,'' where ozone production is primarily determined by the amount of NO_X emissions or ''VOC-limited,'' where ozone production is primarily determined by the amount of VOC emissions.[57] The EPA and others have long regarded NO_X to be the more significant ozone precursor in the context of interstate ozone transport.[58]

The EPA has determined that the regulation of VOCs as an ozone precursor is not necessary to eliminate significant contribution of ozone transport to downwind areas in this proposed rule. As described in Section VI.A of this proposed rule, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Our analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NO_X-limited, rather than VOC-limited. Therefore, the proposed rule's strategy for reducing regional-scale transport of ozone targets NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas.

Commenters on prior ozone transport rules have asserted that VOC emissions harm underserved and overburdened communities experiencing disproportionate environmental health burdens and facing other environmental injustices. The EPA acknowledges that VOCs can contain toxic chemicals that are detrimental to public health. The EPA conducted a demographic analysis as part of the regulatory impact analysis for the 2015 revisions to the primary and secondary ozone NAAQS. This analysis, which is included in the docket for this proposed rulemaking, found greater representation of minority populations in areas with poor air quality relative to the revised ozone standard than in the U.S. as a whole. The EPA concluded that populations in these areas would be expected to benefit from implementation of future air pollution control actions from state and local air agencies in implementing the strengthened standard. This proposed rule is an example of air pollution control actions implemented by the federal government in support of the more stringent 2015 ozone NAAQS, and populations living in downwind ozone nonattainment areas are expected to benefit from improved air quality that will result from reducing ozone transport. Further discussion of the environmental justice impacts of this proposed rule is located in Section VIII of this proposed rule and in the accompanying regulatory impact analysis, titled ''Regulatory Impact Analysis for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452/D–22–001], which is available in the docket for this rulemaking.

The Agency regulates exposure to toxic pollutant concentrations and ambient exposure to criteria pollutants other than ozone through other sections of the Act, such as the regulation of hazardous air pollutants under CAA section 112 or the process for revising and implementing the NAAQS under CAA sections 107–110. The purpose of the proposed rulemaking is to protect public health and the environment by eliminating significant contribution from 26 states to nonattainment or maintenance of the 2015 ozone NAAQS in order to meet the requirements of the CAA's interstate transport provision. In this proposed rule, the EPA continues to observe that requiring NO_X emissions reductions from stationary sources is an effective strategy for reducing regional ozone transport in the U.S.

In Section VI of this proposed rule, EPA describes the multi-factor test that is used to determine NO_X emissions reductions that are cost-effective and reduce interstate transport of ground-level ozone. Our analysis indicates that the EGU and non-EGU control requirements proposed in this rule will provide meaningful improvements in air quality at the downwind receptors. Based on the implementation schedule

[54] Nolte, C.G., P.D. Dolwick, N. Fann, L.W. Horowitz, V. Naik, R.W. Pinder, T.L. Spero, D.A. Winner, and L.H. Ziska, 2018: Air Quality. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 512–538. doi: 10.7930/NCA4.2018.CH13.

[55] Bergin, M.S. et al. (2007) Regional air quality: Local and interstate impacts of NO_X and SO_2 emissions on ozone and fine particulate matter in the eastern United States. Environmental Sci & Tech. 41: 4677–4689.

[56] Butler, et al., ''Response of Ozone and Nitrate to Stationary Source Reductions in the Eastern USA''. *Atmospheric Environment,* 2011.

[57] ''Ozone Air Pollution.'' *Introduction to Atmospheric Chemistry,* by DANIEL J. JACOB, Princeton University Press, PRINCETON, NEW JERSEY, 1999, pp. 231–244.

[58] 81 FR 74514.

established in Section VII.A of this proposed rule, the EPA proposes to determine that the regulatory requirements included in the proposed rule are as expeditious as practicable and are aligned with the attainment schedule of downwind areas.

3. Health and Environmental Effects

Exposure to ambient ozone causes a variety of negative effects on human health, vegetation, and ecosystems. In humans, acute and chronic exposure to ozone is associated with premature mortality and a number of morbidity effects, such as asthma exacerbation. In ecosystems, ozone exposure causes visible foliar injury, decreases plant growth, and affects ecosystem community composition. *See* EPA's October 2015 Regulatory Impact Analysis of the Final Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone [59] in the docket for this proposal for more information on the human health and ecosystem effects associated with ambient ozone exposure.

B. Proposed Rule Approach

1. The 4-Step Interstate Transport Framework

The EPA first developed a multi-step process to address the requirements of the good neighbor provision in the NO_X SIP Call and CAIR. The Agency built upon this framework and further refined the methodology for addressing interstate transport obligations in subsequent rules such as CSAPR, the CSAPR Update, and the Revised CSAPR Update.[60] In CSAPR, the EPA first articulated a ''4-step framework'' within which to assess interstate transport obligations for ozone. In this proposed action to address interstate transport obligations for the 2015 ozone NAAQS, the EPA is again utilizing the 4-step interstate transport framework. These steps are: (1) Identifying downwind receptors that are expected to have problems attaining the NAAQS (nonattainment receptors) or maintaining the NAAQS (maintenance receptors); (2) determining which upwind states are ''linked'' to these identified downwind receptors based on a numerical contribution threshold; (3) for states linked to downwind air quality problems, identifying upwind emissions on a statewide basis that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS, considering cost- and air quality-based factors; and (4) for upwind states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, implementing the necessary emissions reductions through enforceable measures.

a. Step 1 Approach

The EPA proposes to continue to apply the method of the CSAPR Update and the Revised CSAPR Update for identifying nonattainment and maintenance receptors. In the Revised CSAPR Update, the EPA assessed downwind air quality problems using modeled future air quality concentrations for an analytic year aligned with the relevant attainment deadline for the NAAQS under consideration in that rulemaking.[61] Similarly, in CSAPR, downwind air quality problems were assessed using modeled future air quality concentrations for a year aligned with attainment deadlines for the NAAQS considered in that rulemaking. The base case scenario provides an assessment of future air quality conditions that generally accounts for enforceable ''on-the-books'' emissions reductions and provides the most up-to-date forecast of what future emissions would resemble, in the absence of the transport policy in the proposed rule under evaluation. Downwind air quality problems are identified as the locations of monitoring sites that are projected to be unable to attain the NAAQS (''nonattainment receptors'') or as the locations of monitoring sites that are projected to be unable to maintain the NAAQS (''maintenance receptors''). In the CSAPR Update and the Revised CSAPR Update, unlike CSAPR,[62] the EPA also considered currently available monitored air quality data to further inform the identification of projected downwind air quality problems. These same considerations are included for this proposal. Further details regarding the application of Step 1 of the 4-step interstate transport framework in this proposal are described in Section V.D of this proposed rule.

b. Step 2 Approach

The EPA proposes to apply the same approach for identifying which states are contributing to downwind nonattainment and maintenance receptors as it has applied in the three prior CSAPR rulemakings. CSAPR, the CSAPR Update, and the Revised CSAPR Update used a screening threshold of 1 percent of the NAAQS to identify upwind states that were ''linked'' to downwind air pollution problems. States with contributions greater than or equal to the threshold for at least one downwind nonattainment or maintenance receptor identified in Step 1 were identified as needing further evaluation of their good neighbor obligations to downwind states.[63] The EPA evaluated each state's contribution based on the average relative downwind impact calculated over multiple days.[64] States whose air quality impacts to all downwind receptors were below this threshold did not require further evaluation for actions to address transport. In other words, the EPA determined that these states did not contribute to downwind air quality problems and therefore had no emissions reduction obligations under the good neighbor provision. The EPA applies a contribution screening threshold because many downwind ozone nonattainment areas receive transport contributions from a number of upwind states. While the proportion of contribution from a single upwind state may be relatively small, the effect of collective contribution resulting from multiple upwind states may substantially contribute to nonattainment of or interference with maintenance of the NAAQS in downwind areas. The preambles to the

[59] Available at *https://www.epa.gov/sites/default/files/2016-02/documents/20151001ria.pdf.*

[60] *See* CSAPR, Final Rule, 76 FR 48208, 48248–48249 (August 8, 2011); CSAPR Update, Final Rule, 81 FR 74504, 74517–74521 (October 26, 2016).

[61] Specifically, the EPA analyzed 2021 to align with the attainment date for areas classified as Severe nonattainment for the 2008 ozone NAAQS, and because the last full ozone season before that date, in 2020, was already in the past.

[62] In CSAPR, the EPA did not use current monitored air quality conditions, because that data was influenced by the invalidated CAIR rule, which the EPA was replacing with CSAPR. *See* 81 FR 74506, 74531. As the EPA is not replacing an existing transport program in this proposed rule, the Agency proposes to once again consider current monitored data as part of the process for identifying projected receptors for this rulemaking.

[63] For ozone, the impacts include those from VOC and NO_X from all sectors.

[64] The number of days used in calculating the average contribution metric has historically been determined in a manner that is generally consistent with EPA's recommendations for projecting future year ozone design values. Our ozone attainment demonstration modeling guidance at the time of CSAPR recommended using all model-predicted days above the NAAQS to calculate future year design values (*https://www3.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf*). In 2014, the EPA issued draft revised guidance that changed the recommended number of days to the top-10 model predicted days (*https://www3.epa.gov/ttn/scram/guidance/guide/Draft-O3-PM-RH-Modeling_Guidance-2014.pdf*). For the CSAPR Update, the EPA transitioned to calculating design values based on this draft revised approach. The revised modeling guidance was finalized in 2019 and, in this regard, EPA is calculating both the ozone design values and the contributions based on a top-10 day approach (*https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf*).

proposed and final CSAPR rules discuss the use of the 1 percent threshold for CSAPR. *See* 75 FR 45237 (August 2, 2010); 76 FR 48238 (August 8, 2011). The same metric is discussed in the CSAPR Update, *see* 81 FR 74538, and in the Revised CSAPR Update, *see* 86 FR 23054. In this proposed rule, the EPA updated the air quality modeling data used for determining contributions at Step 2 of the four-step interstate transport framework. The EPA otherwise continues to find that this threshold is appropriate to continue to apply for the 2015 ozone NAAQS. This proposal's application of the Step 2 approach is comprehensively described in Section V of this proposed rule.

c. Step 3 Approach

The EPA proposes to continue to apply the same approach as the prior three CSAPR rulemakings for evaluating ''significant contribution'' at Step 3.[65] For states that are linked in Step 3 to downwind air quality problems, CSAPR, the CSAPR Update, and the Revised CSAPR Update evaluated NO_X reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds) in the multi-factor test. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA selected the technology breakpoint (represented by a cost threshold) that, in general, maximized cost-effectiveness—*i.e.,* that achieved a reasonable balance of incremental NO_X reduction potential and corresponding downwind ozone air quality improvements, relative to the other emissions budget levels evaluated. *See, e.g.,* 81 FR 74550. The EPA determined the level of emissions reductions associated with that level of control stringency to constitute significant contribution to nonattainment or interfere with maintenance of a NAAQS downwind. *See, e.g.,* 86 FR 23116. This approach was upheld by the U.S. Supreme Court in *EPA* v. *EME Homer City.*[66]

The EPA proposes in this action to apply this approach to identify EGU and non-EGU NO_X control stringencies necessary to address significant contribution for the 2015 ozone NAAQS. The EPA applies a multifactor assessment using cost-thresholds, total emissions reduction potential, and downwind air quality effects as key factors in determining a reasonable balance of NO_X controls in light of the downwind air quality problems. EPA's evaluation of available NO_X mitigation strategies for EGUs focuses on the same core set of measures as prior transport rules, and the EPA proposes a control stringency for EGUs from these measures that is commensurate with the nature of the ongoing ozone nonattainment and maintenance problems observed for the 2015 ozone NAAQS. Similarly, in this action, the EPA includes other industrial sources (non-EGUs) in its Step 3 analysis and proposes emissions limitations for certain non-EGU sources as needed to eliminate significant contribution and interference with maintenance. The available reductions and cost-levels for the non-EGU stringency is generally commensurate with the control strategy for EGUs.

In CSAPR, the CSAPR Update, and the Revised CSAPR Update, EPA focused its Step 3 analysis on EGUs. In the Revised CSAPR Update, in response to the *Wisconsin* decision's finding that the EPA had not adequately evaluated potential non-EGU reductions, *see* 938 F.3d at 318, the EPA determined that the available NO_X emissions reductions from non-EGU sources, for purposes of addressing good neighbor obligations for the 2008 ozone NAAQS, at a comparable cost threshold to the required EGU emissions reductions (for which EPA used an adjusted representative cost of $1,800 per ton), and based on the timing of when such measures could be implemented, did not provide a sufficiently meaningful and timely air quality improvement at the downwind receptors before those receptors were projected to resolve. *See* 86 FR 23110. On that basis, the EPA made a finding that emissions reductions from non-EGU sources were not required to eliminate significant contribution to downwind air quality problems under the interstate transport provision for the 2008 ozone NAAQS. In this proposal, EPA's ''significant contribution'' analysis at Step 3 of the 4-step framework includes a comprehensive evaluation of major stationary source non-EGU industries in the linked upwind states. The EPA is proposing to find that emissions from certain non-EGU sources in the upwind states significantly contribute to downwind air quality problems for the 2015 ozone NAAQS, and that cost-effective emissions reductions from these sources are required to eliminate significant contribution under the interstate transport provision. Therefore, this proposed rule includes required emissions reductions from non-EGU sources in upwind states to fulfill interstate transport obligations for the 2015 ozone NAAQS. This analysis is described fully in Section VI of the proposed rule.

In this proposed rule, the EPA also continues to apply its approach for assessing and avoiding ''over-control.'' In *EME Homer City,* the Supreme Court held that ''EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set.'' 572 U.S. at 521. The Court acknowledged that ''instances of 'over-control' in particular downwind locations may be incidental to reductions necessary to ensure attainment elsewhere.'' *Id.* at 492.

> ''Because individual upwind States often 'contribute significantly' to nonattainment in multiple downwind locations, the emissions reductions required to bring one linked downwind State into attainment may well be large enough to push other linked downwind States over the attainment line. As the Good Neighbor Provision seeks attainment in *every* downwind State, however, exceeding attainment in one State cannot rank as 'over-control' unless unnecessary to achieving attainment in *any* downwind State. Only reductions unnecessary to downwind attainment *anywhere* fall outside the Agency's statutory authority.''

Id. at 522 (footnotes excluded).

The Court further explained that ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' *Id.* at 523. Therefore, in the CSAPR Update and Revised CSAPR Update, the EPA evaluated possible over-control by considering whether an upwind state is linked solely to downwind air quality problems that can be resolved at a lower cost threshold, or if upwind states would reduce their emissions at a lower cost threshold to the extent that they would no longer meet or exceed the 1 percent air quality contribution threshold. *See, e.g.,* 81 FR at 74551–52. *See also Wisconsin,* 938 F.3d at 325

[65] For simplicity, the EPA (and courts) at times will refer to the Step 3 analysis as determining ''significant contribution''; however, EPA's approach at Step 3 also implements the ''interference with maintenance'' prong of the good neighbor provision, by also addressing emissions that impact the maintenance receptors identified at Step 1. *See* 86 FR 23074 (''In effect, EPA's determination of what level of upwind contribution constitutes 'interference' with a maintenance receptor is the same determination as what constitutes 'significant contribution' for a nonattainment receptor. Nonetheless, this continues to give independent effect to prong 2 because the EPA applies a broader definition for identifying maintenance receptors, which accounts for the possibility of problems maintaining the NAAQS under realistic potential future conditions.'').

[66] *EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489 (2014).

(over-control must be proven through a "'particularized, as-applied challenge'") (quoting *EME Homer City Generation,* 572 U.S. at 523–24). The EPA continues to apply this framework for assessing over-control in this proposed rule, and, as discussed in Section VI.D.4 of this proposed rule, does not find any over-control at the proposed stringency to be sufficiently certain to warrant a relaxation in requirements for the sources in any covered state.

This evaluation of cost, NO_X reductions, and air quality improvements, including consideration of whether there is proven over-control, results in EPA's determination of the appropriate level of upwind control stringency that would result in elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas.

d. Step 4 Approach

The EPA proposes an approach similar to its prior transport rulemakings to implement the necessary emissions reductions through permanent and enforceable measures. The EPA proposes to require EGU sources to participate in an emissions trading program and proposes additional enhancements to the trading regime to maintain the selected control stringency over time and improve emissions performance at individual units, offering a necessary measure of assurance that emissions controls will be operated throughout the ozone season. For non-EGUs, the EPA proposes permanent and enforceable emissions rate limits and work practice standards, and associated compliance requirements, on several types of NO_X-emitting combustion units across several industrial sectors. The measures for both EGUs and non-EGUs are proposed to be required throughout the May 1–September 30 ozone season annually. The EGU program will begin with the 2023 ozone season, and non-EGU implementation will begin with the 2026 ozone season. Refer to Section VII.A of this proposed rule for details on the implementation schedule.

Based on the EPA's experience in implementing prior transport rulemakings, the Agency is proposing several enhancements to its trading-program approach for implementing good neighbor requirements for EGUs. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA established interstate trading programs for EGUs to implement the necessary emissions reductions. In each of these rules, EGUs in each covered state are assigned an emissions budget for their collective emissions. Emissions allowances are allocated to units covered by the trading program, and the covered units then surrender allowances after the close of each control period, usually in an amount equal to their ozone season EGU NO_X emissions. While these programs have been effective in achieving overall reductions in emissions, experience has shown that these programs may not fully reflect in perpetuity the degree of emissions stringency determined necessary to eliminate significant contribution in Step 3 and may not adequately ensure the control of emissions throughout all days of the ozone season. At the same time, the EPA continues to find that an interstate-trading program approach delivers substantial benefits at Step 4 in terms of affording an appropriate degree of compliance flexibility, certainty in emissions outcomes, data and performance transparency, and cost-effective achievement of a high degree of aggregate emissions reductions. As such, EPA proposes to retain an interstate trading program approach while proposing several enhancements to that approach.

Thus, in this rulemaking, the EPA is proposing to include budget-setting procedures in the regulations that will allow state emissions budgets for control periods in 2025 and later years to reflect more current data on the composition and utilization of the EGU fleet (*e.g.,* the 2025 budgets would reflect 2023 data, the 2026 budgets would reflect 2024 data, etc.). These enhancements would enable the trading program to better maintain over time the selected control stringency that was determined to be necessary to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. In prior programs, where state emissions budgets were static across years rather than calibrated to yearly fleet changes, the EPA has observed instances of units idling their emission controls in the latter years of the program.

In the trading programs established for ozone season NO_X emissions under CSAPR, the CSAPR Update, and the Revised CSAPR Update, the EPA included assurance provisions to limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders in the instance that emissions in the state exceed this level. This limit on the degree to which a state's emissions can exceed its budget is designed to allow for a certain level of year-to-year variability within power sector emissions to account for fluctuations in demand and EGU operations and is responsive to previous court decisions (see discussion in Section VII.B.4 of this proposed rule). In this action, the EPA again proposes to retain the existing assurance provisions that limit state emissions to levels below 121 percent of the state's budget by requiring additional allowance surrenders in the instance that emissions in the state exceed this level for the 2023 and 2024 control periods. For control periods in 2025 and later years, the EPA is proposing to maintain the same general approach, but with adjustments that account for actual operational conditions in each control period to determine the specific levels above which additional allowance surrenders would be required. In addition, EPA is also proposing several additional enhancements to the EGU trading program in this action, including routine recalibrations of the total amount of banked allowances, unit-specific backstop daily emissions rates for certain units, and unit-specific secondary emissions limitations for units that contribute to exceedances of the assurance levels, to ensure EGU emissions control operation and associated air quality improvements. Implementation of the proposed EGU emissions reductions using a CSAPR NO_X trading program is further described in Section VII.B of this proposed rule.

In this action, the EPA is also proposing to establish emissions limitations for the non-EGU industry sources listed in Table III.A–1. The EPA has the authority to require emissions limitations from stationary sources, as well as from other sources and emissions activities, under CAA section 110(a)(2)(D)(i)(I). The EPA proposes that requiring NO_X emissions reductions through emissions rate limits from certain non-EGU industry sources that the EPA found at Step 3 to be relatively impactful[67] on downwind air quality is an effective strategy for reducing regional ozone transport. Therefore, the EPA proposes NO_X emissions limitations and associated compliance requirements for non-EGU sources to ensure the elimination of significant contribution of ozone precursor emissions required under the interstate

[67] *Section III of the* Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes EPA's approach to evaluating impacts on downwind air quality, considering estimated total, maximum, and average contributions from each industry and the total number of receptors with contributions from each industry.

transport provision for the 2015 ozone NAAQS.

Finally, the EPA proposes that the control measures determined to be required for the identified EGU and non-EGU sources apply to both existing units and any new, modified, or reconstructed units meeting the applicability criteria established in this proposal. This is consistent with EPA's transport actions dating back to the NO_X SIP Call and the NO_X Budget Trading Program. In all CSAPR EGU trading programs, for instance, new EGUs are subject to the program, and the EPA established provisions for the allocation of allowances to such units through ''new unit set asides.'' *See, e.g.,* 86 FR 23126. In the NO_X SIP Call, the EPA required that states cover new and existing units in the relevant source sectors through an enforceable cap or other emissions limitation. *See* 40 CFR 51.121(f). EPA's approach of including new units in the NO_X Budget Trading Program promulgated under EPA's CAA section 126 authority was upheld by the D.C. Circuit in *Appalachian Power* v. *EPA,* 249 F.3d 1032 (2001). The EPA explained in its action:

> Once EPA has determined that the emissions from the existing sources in an upwind State already make a significant contribution to one or more petitioning downwind States, any additional emissions from a new source in that upwind State would also constitute a portion of that significant contribution, unless the emissions from that new source are limited to the level of highly effective controls.

Id. at 1058 (quoting EPA 1999 RTC at 39). The court affirmed this approach: ''Indeed, it would be irrational to enable the EPA to make findings that a group of sources in an upwind state contribute to downwind nonattainment, but then preclude the EPA from regulating new sources that contribute to that same pollution.'' *Id.* at 1057–58. The EPA proposes to adopt the same approach in this action, because this reasoning is equally applicable to addressing interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

2. FIP Authority for Each State Covered by the Proposed Rule

On October 1, 2015, the EPA promulgated a revision to the 2015 8-hour ozone NAAQS, lowering the level of both the primary and secondary standards to 0.070 parts per million (ppm).[68] These revisions of the NAAQS, in turn, established a 3-year deadline for states to provide SIP submissions addressing infrastructure requirements under CAA sections 110(a)(1) and 110(a)(2), including the good neighbor provision, by October 1, 2018. If the EPA makes a determination that a state failed to submit a SIP, or if EPA disapproves a SIP submission, then the EPA is obligated under CAA section 110(c) to promulgate a FIP for that state within 2 years. For a more detailed discussion of CAA section 110 authority and timelines, refer to Section III.C of this proposed rule.

The EPA is proposing this FIP action now to address twenty-six states' good neighbor obligations for the 2015 ozone NAAQS, but the EPA will not finalize this FIP action for any state unless and until it has issued a final finding of failure to submit or a final disapproval of that state's SIP submission. The EPA is not required to wait to propose a FIP until after the Agency proposes or finalizes a SIP disapproval or makes a finding of failure to submit.[69] CAA section 110(c) authorizes EPA to *promulgate* a FIP ''at any time within 2 years'' of a SIP disapproval or making a finding of failure to submit. Thus, the EPA may promulgate a FIP contemporaneously with or immediately following predicate final action on a SIP (or finding no SIP was submitted). In order to accomplish this, the EPA must necessarily be able to propose a FIP prior to taking final action to disapprove a SIP or make a finding of failure to submit. The Supreme Court recognized this in *EME Homer City* in holding that the EPA is not obligated to first define a state's good neighbor obligations or give the state an additional opportunity to submit an approvable SIP before promulgating a FIP: ''EPA is not obliged to wait two years or postpone its action even a single day: The Act empowers the Agency to promulgate a FIP 'at any time' within the two-year limit.'' [70] Furthermore, the D.C. Circuit in *Wisconsin* held that states and EPA are obligated to fully address good neighbor obligations for ozone ''as expeditiously as practical'' and in no event later than the next relevant downwind attainment dates found in CAA section 181(a).[71] In *Maryland* v. *EPA,* the D.C. Circuit made clear that *Wisconsin's* and *North Carolina's* holdings are fully applicable to the Marginal area attainment date for the 2015 ozone NAAQS,[72] which fell on August 3, 2021.[73] The *Wisconsin* court emphasized that EPA has the authority under CAA section 110 to structure and time its actions in a manner such that the Agency can ensure necessary reductions are achieved by the downwind attainment dates.[74]

On February 22, 2022, the EPA proposed to disapprove 19 good neighbor SIP submissions (Alabama, Arkansas, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Tennessee, Texas, West Virginia, Wisconsin).[75] The EPA is proposing to

[68] *National Ambient Air Quality Standards for Ozone,* Final Rule, 80 FR 65292 (October 26, 2015). Although the level of the standard is specified in the units of ppm, ozone concentrations are also described in parts per billion (ppb). For example, 0.070 ppm is equivalent to 70 ppb.

[69] The EPA notes there are three consent decrees to resolve three deadline suits related to EPA's duty to act on good neighbor SIP submissions for the 2015 ozone NAAQS. In *New York et al.* v. *Regan, et al.* (No. 1:21–CV–00252, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Indiana, Kentucky, Michigan, Ohio, Texas, and West Virginia by April 30, 2022; however, if the EPA proposes to disapprove any SIP submissions and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on that SIP submission is extended to December 30, 2022. In *Downwinders at Risk et al.* v. *Regan* (No. 21–cv–03551, N.D. Cal.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submissions from Alabama, Arkansas, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, New Jersey, New York, North Carolina, Ohio, Oklahoma, South Carolina, Tennessee, Texas, West Virginia, and Wisconsin by April 30, 2022; however, if the EPA proposes to disapprove any of these SIP submissions and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on that SIP submission is December 30, 2022. In this CD, the EPA also agreed to take final action on Hawaii's SIP submission by April 30, 2022, and to take final action on the SIP submissions of Arizona, California, Montana, Nevada, and Wyoming by December 15, 2022. In *Our Children's Earth Foundation* v. *EPA* (No. 20–8232, S.D.N.Y.), the EPA agreed to take final action on the 2015 ozone NAAQS good neighbor SIP submission from New York by April 30, 2022; however, if the EPA proposes to disapprove New York's SIP submission and proposes a replacement FIP by February 28, 2022, then EPA's deadline to take final action on New York's SIP submission is extended to December 30, 2022.

[70] *See EPA* v. *EME Homer City Generation, L.P.,* 572 U.S. 489, 509 (2014) (citations omitted).

[71] *Wisconsin* v. *EPA,* 938 F.3d 303, 313–14 (D.C. Cir. 2019) (citing *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008).

[72] *Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020).

[73] *See* CAA section 181(a); 40 CFR 51.1303; *Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards,* 83 FR 25776 (June 4, 2018, effective August 3, 2018).

[74] 938 F.3d at 318 (''When EPA determines a State's SIP is inadequate, EPA presumably must issue a FIP that will bring that State into compliance before upcoming attainment deadlines, even if the outer limit of the statutory timeframe gives EPA more time to formulate the FIP.'') (citing *Sierra Club* v. *EPA,* 294 F.3d 155, 161 (D.C. Cir. 2002)).

[75] *See* 87 FR 9463 (Maryland); 87 FR 9484 (New Jersey, New York); 87 FR 9498 (Kentucky); 87 FR 9516 (West Virginia); 87 FR 9533 (Missouri); 87 FR 9545 (Alabama, Mississippi, Tennessee); 87 FR 9798 (Arkansas, Louisiana, Oklahoma, Texas); 87 FR 9838 (Illinois, Indiana, Michigan, Minnesota,

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promulgate 2015 ozone NAAQS good neighbor FIPs for these same states, as well as California, Nevada, and Wyoming, but will not finalize a FIP for any of these states unless and until the EPA formally finalizes disapprovals of their SIP submittals or, in the event that any of these states withdraw their good neighbor SIP submissions after this proposal, makes a finding of failure to submit.[76] *See* CAA section 110(c).

Additionally, the EPA has taken action that has triggered EPA's obligation under CAA section 110(c) to promulgate FIPs addressing the good neighbor provision for some other states. On December 5, 2019, the EPA published a rule finding that seven states (Maine, New Mexico, Pennsylvania, Rhode Island, South Dakota, Utah, and Virginia) failed to submit or otherwise make complete submissions that address the requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.[77] This finding triggered a 2-year deadline for the EPA to issue FIPs to address the good neighbor provision for these states by January 6, 2022. As the EPA has subsequently received and taken final action to approve good neighbor SIPs from Maine, Rhode Island, and South Dakota,[78] the EPA currently has authority under the December 5, 2019, finding of failure to submit to issue FIPs for New Mexico, Pennsylvania, Utah, and Virginia. In this proposal, EPA is issuing proposed FIP requirements for Pennsylvania, Utah, and Virginia.[79]

C. Other CAA Authorities for This Action

1. Correction of EPA's Determination Regarding Delaware's SIP Submission and Its Impact on EPA's FIP Authority for Delaware

In 2020, the EPA approved an infrastructure SIP submission from Delaware for the 2015 ozone NAAQS, which in part addressed the good neighbor provision at CAA section 110(a)(2)(D)(i)(I).[80] The EPA concluded that, based on the modeling results presented in a 2018 March memorandum and using a 2023 analytic year, Delaware's largest impact on any potential downwind nonattainment or maintenance receptor was less than 1 percent of the NAAQS.[81] As a result, the EPA found that Delaware would not significantly contribute to nonattainment or interfere with maintenance in any other state.[82] Therefore, the EPA approved the portion of Delaware's infrastructure SIP that addressed CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS.

Subsequent to the release of the modeling data shared in the March 2018 memorandum and EPA's approval of Delaware's 2015 ozone NAAQS good neighbor SIP submission, the EPA performed updated modeling, as described in Section V of this proposed rule. The data from this updated air quality modeling now show that Delaware is projected to contribute more than 1 percent of the NAAQS to downwind receptors in Bristol, Pennsylvania, in the 2023 analytic year.[83] Therefore, in light of the modeling data, EPA is proposing to find that its approval of Delaware's 2015 ozone NAAQS infrastructure SIP submission, with regard only to the portion addressing the good neighbor provision at CAA section 110(a)(2)(D)(i)(I), was in error. Section 110(k)(6) of the CAA gives the Administrator authority, without any further submission from a state, to revise certain prior actions, including actions to approve SIPs, upon determining that those actions were in error.[84] The modeling data demonstrate that EPA's prior conclusion that Delaware will not significantly contribute to nonattainment or interfere with maintenance in any other state in the 2023 analytic year was incorrect, which means that EPA's approval of Delaware's good neighbor SIP submission was in error.

Therefore, the EPA proposes to correct the error in Delaware's good neighbor SIP approval. This error correction under CAA section 110(k)(6) would revise the approval of the portion of Delaware's 2015 ozone NAAQS infrastructure SIP that addresses CAA section 110(a)(2)(D)(i)(I) to a disapproval and rescind any statements that the portion of Delaware's infrastructure SIP submission that addresses CAA section 110(a)(2)(D)(i)(I) satisfies the requirements of the good neighbor provision. The EPA is not proposing to correct the elements of Delaware's 2015 ozone NAAQS infrastructure SIP that do not address CAA section 110(a)(2)(D)(i)(I).

As discussed in greater detail in the sections that follow, the EPA is proposing to determine that there are additional emissions reductions that are required for Delaware to satisfy its good neighbor obligations for the 2015 ozone NAAQS. The analysis on which the EPA proposes this conclusion for Delaware is the same, regionally consistent analytical framework on which the Agency proposes FIP action for the other states included in this proposal. The Agency recognizes that it is possible, based on updated information for the final rule—as applied within a regionally consistent analytical framework—that Delaware (or other states for which the EPA proposes FIPs in this action) may be found to have no further interstate transport obligation for the 2015 ozone NAAQS. If such a circumstance were to occur, the EPA anticipates that it would not finalize this proposed error correction or may modify the error correction such that the approval of Delaware's portion of the SIP as it relates to its good neighbor obligations may be affirmed.

Ohio, Wisconsin). EPA has not yet proposed action on interstate transport SIPs submitted by California, Nevada, Utah, and Wyoming.

[76] See the document titled ''Status of CAA Section 110(a)(2)(D)(i)(I) SIP Submissions for the 2015 Ozone NAAQS for States Covered by the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards,'' included in the docket for this rulemaking, for additional information on EPA's statutory authorities for this proposed rule.

[77] *Findings of Failure To Submit a Clean Air Act Section 110 State Implementation Plan for Interstate Transport for the 2015 Ozone National Ambient Air Quality Standards (NAAQS),* 84 FR 66612 (December 5, 2019, effective January 6, 2020).

[78] *Air Plan Approval; Maine and New Hampshire; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 45870 (August 17, 2021); *Air Plan Approval; Rhode Island; 2015 Ozone NAAQS Interstate Transport Requirements,* 86 FR 70409 (December 10, 2021); *Promulgation of State Implementation Plan Revisions; Infrastructure Requirements for the 2015 Ozone National Ambient Air Quality Standards; South Dakota; Revisions to the Administrative Rules of South Dakota,* 85 FR 29882 (May 19, 2020).

[79] The EPA has not yet taken action on a subsequent good neighbor SIP submission from New Mexico or Utah; EPA is not including New Mexico in this proposed action.

[80] *Approval and Promulgation of Air Quality Implementation Plans; Delaware; Infrastructure Requirements for the 2015 Ozone Standard and Revisions to Modeling Requirements,* 85 FR 25307 (May 1, 2020).

[81] ''Technical Support Document for the Delaware State Implementation Plan for the Infrastructure Requirements for the 2015 Ozone Standard and Revisions to Modeling Requirements'' at 16, available in Docket No. EPA–R03–OAR–2019–0663.

[82] *Id.* at 17. Based on the 2023 modeling from the 2018 memorandum, Delaware was expected in 2023 to have a 0.40 ppb impact on a potential nonattainment receptor in Fairfield, Connecticut (Site ID 90019003) and a 0.38 ppb impact at a potential maintenance receptor in Queens, New York (Site ID 360810124).

[83] The contribution from Delaware in 2023 to the receptor in Bristol, Pennsylvania, is 1.36 ppb.

[84] *See, e.g.,* 86 FR 23054, 23068 (error correcting prior approval of Kentucky's transport SIP submission for the 2008 ozone NAAQS to a disapproval and simultaneously promulgating FIP on the basis of the *Wisconsin* and *New York* decisions remanding CSAPR Update and vacating CSAPR Close-Out and new information establishing Kentucky was linked to downwind receptors).

2. Application of Rule in Indian Country and Necessary or Appropriate Finding

The EPA proposes that this rule will be applicable in all areas of Indian country (as defined at 18 U.S.C. 1151) within the covered geography of the proposal, as defined below. Currently, certain areas of Indian country within the geography of the proposal are subject to state implementation planning authority. Other areas of Indian country within that geography would be subject to tribal planning authority, although none of the relevant tribes have as yet sought eligibility to administer a tribal plan to implement the good neighbor provision.[85] As described later, the EPA is proposing to include all areas of Indian country within the covered geography, notwithstanding whether those areas are currently subject to a state's implementation planning authority or the potential planning authority of a tribe.

With respect to areas of Indian country not currently subject to a state's implementation planning authority—*i.e.,* Indian reservation lands (with the partial exception of reservation lands located in the State of Oklahoma, as described further below) and other areas of Indian country over which the EPA or a tribe has demonstrated that a tribe has jurisdiction—the EPA here proposes a ''necessary or appropriate'' finding that direct federal implementation of the rule's requirements is warranted under CAA section 301(d)(4) and 40 CFR 49.11(a) (the areas of Indian country subject to this finding are referred to later as the 301(d) FIP areas). Indian Tribes may, but are not required to, submit tribal plans to implement CAA requirements, including the good neighbor provision. Section 301(d) of the CAA and 40 CFR part 49 authorize the Administrator to treat an Indian Tribe in the same manner as a state (*i.e.,* TAS) for purposes of developing and implementing a tribal plan implementing good neighbor obligations. *See* 40 CFR 49.3; *see also* ''Indian Tribes: Air Quality Planning and Management,'' hereafter ''Tribal Authority Rule,'' (63 FR 7254, February 12, 1998). The EPA is authorized to directly implement the good neighbor provision in the 301(d) FIP areas when it finds, consistent with the authority of CAA section 301—which the EPA has exercised in 40 CFR 49.11—that it is necessary or appropriate to do so.[86]

The EPA proposes in this action to find that it is both necessary and appropriate to regulate all new and existing EGU and non-EGU sources meeting the applicability criteria set forth in this proposed rule in all of the 301(d) FIP areas that are located within the geographic scope of coverage of the rule. For purposes of this proposed finding, the geographic scope of coverage of the rule means the areas of the United States encompassed within the borders of the states EPA has determined to be linked at Steps 1 and 2 of the 4-step interstate transport framework.[87] For EGU applicability criteria, *see* Section VII.B of this proposed rule; for non-EGU applicability criteria, *see* Section VII.C of this proposed rule. To EPA's knowledge, only one existing EGU or non-EGU source is located within the 301(d) FIP areas: The Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah.

This proposed finding is consistent with EPA's prior good neighbor rules. In prior rulemakings under the good neighbor provision, the EPA has included all areas of Indian country within the geographic scope of those FIPs, such that any new or existing sources meeting the rules' applicability criteria would be subject to the rule irrespective of whether subject to state or tribal underlying CAA planning authority. In CSAPR, the CSAPR Update, and the Revised CSAPR Update, the scope of the emissions trading programs established for EGUs extended to cover all areas of Indian country located within the geographic boundaries of the covered states. In these rules, at the time of their promulgation, no existing units were located in the covered areas of Indian country; under the general applicability criteria of the trading programs, however, any new sources locating in such areas would become subject to the programs. Thus, EPA established a separate allowance allocation that would be available for any new units locating in any of the relevant areas of Indian country. *See, e.g.,* 76 FR at 48293 (describing the CSAPR methodology of allowance allocation under the ''Indian country new unit set-aside'' provisions); *see also id.* at 48217 (explaining EPA's source of authority for directly regulating in relevant areas of Indian country as necessary or appropriate). Further, in any action in which the EPA subsequently approved a state's SIP submittal to partially or wholly replace the provisions of a CSAPR FIP, EPA has clearly delineated that it will continue to administer the Indian country new unit set aside for sources in any areas of Indian country geographically located within a state's borders and not subject to that state's CAA planning authority, and the state may not exercise jurisdiction over any such sources. *See, e.g.,* 82 FR 46674, 46677 (October 6. 2017) (approving Alabama's SIP submission establishing a state CSAPR trading program for ozone season NO_X, but providing, ''The SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction.'').

In this proposed rule, the EPA proposes to take an approach similar to the prior CSAPR rulemakings with respect to regulating sources in the 301(d) FIP areas.[88] The EPA believes this approach is necessary and appropriate for several reasons. First, the purpose of this rule is to address the

[85] We note that, consistent with EPA's prior good neighbor actions in California, the regulatory ozone monitor located on the Morongo Band of Mission Indians (''Morongo'') reservation is a projected downwind receptor in 2023. *See* monitoring site 060651016 in Table V.D–1. We also note that the Temecula, California regulatory ozone monitor is a projected downwind receptor in 2023 and in past regulatory actions has been deemed representative of air quality on the Pechanga Band of Luiseño Indians (''Pechanga'') reservation. *See, e.g., Approval of Tribal Implementation Plan and Designation of Air Quality Planning Area; Pechanga Band of Luiseño Mission Indians,* 80 FR 18120, at 18121–18123 (April 3, 2015); *see also* monitoring site 060650016 in Table V.D–1. The presence of receptors on, or representative of, the Morongo and Pechanga reservations does not trigger obligations for the Morongo and Pechanga Tribes. Nevertheless, these receptors are relevant to EPA's assessment of any linked upwind states' good neighbor obligations. *See, e.g., Approval and Promulgation of Air Quality State Implementation Plans; California; Interstate Transport Requirements for Ozone, Fine Particulate Matter, and Sulfur Dioxide,* 83 FR 65093 (December 19, 2018). Under 40 CFR 49.4(a), tribes are not subject to the specific plan submittal and implementation deadlines for NAAQS-related requirements, including deadlines for submittal of plans addressing transport impacts.

[86] *See Arizona Pub. Serv. Co.* v. *U.S. E.P.A.,* 562 F.3d 1116, 1125 (10th Cir. 2009) (stating that 40 CFR 49.11(a) ''provides the EPA discretion to determine what rulemaking is necessary or appropriate to protect air quality and requires the EPA to promulgate such rulemaking''); *Safe Air For Everyone* v. *U.S. Env't Prot. Agency,* No. 05–73383, 2006 WL 3697684, at *1 (9th Cir., Dec. 15, 2006) (''The statutes and regulations that enable EPA to regulate air quality on Indian reservations provide EPA with broad discretion in setting the content of such regulations.'').

[87] With respect to any non-EGU sources located in the 301(d) FIP areas, the geographic scope of coverage of this proposed rule does not include those states for which EPA proposes to find, based on air quality modeling, that no further linkage exists by the 2026 analytic year at Steps 1 and 2. The states no longer projected to be linked in 2026 are Alabama, Delaware, and Tennessee.

[88] *See* Section VII.B.9 of this action for a discussion of revisions that are proposed in this rulemaking regarding the point in the allowance allocation process at which the EPA would establish set-asides of allowances for units in Indian country not subject to a state's CAA implementation planning authority.

interstate transport of ozone on a national scale, and the technical record establishes that the nonattainment and maintenance receptors located throughout the country are impacted by sources of ozone pollution on a broad geographic scale. The upwind regions associated with each receptor typically span at least two, and often far more, states. Within the broad upwind region covered by this proposal, the EPA proposes to apply—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO_X SIP Call—a uniform level of control stringency. (*See* Section VI of this proposed rule for a discussion of EPA's determination of control stringency for this proposal.) Within this approach, consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is, in the words of the Supreme Court, ''efficient and equitable,'' 572 U.S. 489, 519. In particular, as the Supreme Court found in *EME Homer City Generation,* allocating responsibility through uniform levels of control across the entire upwind geography is ''equitable'' because, by imposing uniform cost thresholds on regulated States, EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to bring down their emissions by installing devices of the kind in which neighboring States have already invested. *Id.*

In the context of addressing regional-scale ozone transport in this proposal, a uniform level of stringency that extends to and includes the 301(d) FIP areas geographically located within the boundaries of the linked upwind states carries significant force. Failure to include all such areas within the scope of the rule creates a significant risk that these areas may be targeted for the siting of facilities emitting ozone-precursor pollutants, in order to avoid the regulatory costs that would be imposed under this proposed rule in the surrounding areas of state jurisdiction. Electricity generation or the production of other goods and commodities may become more cost-competitive at any EGUs or non-EGUs not subject to the rule but located in a geography where all surrounding facilities in the same industrial category are subject to the rule. For instance, the affected EGU source located on the Uintah and Ouray Reservation of the Ute Tribe is in an area that is interconnected with the western electricity grid and is owned and operated by an entity that generates and provides electricity to customers in several states. It is both necessary and appropriate, in EPA's view, to avoid creating, via this proposed rule, a structure of incentives that may cause generation or production—and the associated NO_X emissions—to shift into the 301(d) FIP areas to escape regulation needed to eliminate interstate transport under the good neighbor provision.

The EPA believes it is appropriate to propose direct federal implementation of the proposed rule's requirements in the 301(d) FIP areas at this time rather than at a later date. Tribes have the opportunity to seek TAS and to undertake tribal implementation plans under the CAA. To date, the one tribe which could develop and seek approval of a tribal implementation plan to address good neighbor obligations with respect to an existing EGU in the 301(d) FIP areas for the 2015 ozone NAAQS (or for any other NAAQS), the Ute Indian Tribe of the Uintah and Ouray Reservation, has not expressed an intent to do so. Nor has the EPA heard such intentions from any other tribe, and it would not be reasonable to expect tribes to undertake that planning effort, particularly when no existing sources are currently located on their lands. Further, the EPA is mindful that under court precedent, the EPA and states generally bear an obligation to fully implement any required emissions reductions to eliminate significant contribution under the good neighbor provision as expeditiously as practicable and in alignment with downwind areas' attainment schedule under the Act. As discussed in Section VII.A of this proposed rule, the EPA anticipates implementing certain required emissions reductions by the 2023 ozone season, the last full ozone season before the 2024 Moderate area attainment date, and other key additional required emissions reductions by the 2026 ozone season, the last full ozone season before the 2027 Serious area attainment date. Absent this proposed federal implementation plan in the 301(d) FIP areas, NO_X emissions from any existing or new EGU or non-EGU sources located in, or locating in, the 301(d) FIP areas within the covered geography of the rule would remain unregulated and could potentially increase. This would be inconsistent with EPA's overall goal of aligning good neighbor obligations with the downwind areas' attainment schedule and to achieve emissions reductions as expeditiously as practicable.

Further, the EPA recognizes that Indian country, including the 301(d) FIP areas, is often home to communities with environmental justice concerns, and these communities may bear a disproportionate level of pollution burden as compared with other areas of the United States. EPA's draft Strategic Plan for Fiscal Year 2022–2026 [89] includes an objective to promote environmental justice at the Federal, Tribal, state, and local levels and states: ''Integration of environmental justice principles into all EPA activities with Tribal governments and in Indian country is designed to be flexible enough to accommodate EPA's Tribal program activities and goals, while at the same time meeting the Agency's environmental justice goals.'' By including all areas of Indian country within the covered geography of the rule, the EPA is advancing environmental justice, lowering pollution burdens in such areas, and preventing the potential for ''pollution havens'' to form in such areas as a result of facilities seeking to locate there to avoid the requirements that would otherwise apply outside of such areas under this proposed rule.

Therefore, in order to ensure timely alignment of all needed emissions reductions with the larger timetable of this proposed rule, to ensure equitable distribution of the upwind pollution reduction obligation across all upwind jurisdictions, to avoid perverse economic incentives to locate sources of ozone-precursor pollution in the 301(d) FIP areas, and to deliver greater environmental justice to tribal communities in line with Executive Order 13985: Advancing Racial Equity and Support for Underserved Communities Through the Federal Government,[90] EPA proposes to find it both necessary and appropriate that all existing and new EGU and non-EGU sources that are located in the 301(d) FIP areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. The EPA proposes this finding under section 301(d)(4) of the Act and 40 CFR 49.11. Further, in order to avoid ''unreasonable delay'' in

[89] *https://www.epa.gov/system/files/documents/2021-10/fy-2022-2026-epa-draft-strategic-plan.pdf*

[90] Executive Order 13985 (January 20, 2021): *https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executiveorder-advancing-racial-equity-and-support-for-underserved-communities-through-the-federal-government/.*

promulgating this FIP, as required under section 49.11, the EPA believes it is appropriate to make this proposed finding now, in order to align emissions reduction obligations for any covered new or existing sources in the 301(d) FIP areas with the larger schedule of reductions under this proposed rule. Because all other covered EGU and non-EGU sources within the geography of this proposed rule would be subject to emissions reductions of uniform stringency beginning in the 2023 ozone season, and as necessary to fully and expeditiously address good neighbor obligations for the 2015 ozone NAAQS, there is little benefit to be had by not proposing to include the 301(d) FIP areas in this rule now and a potentially significant downside to not doing so.

The Agency recognizes that Tribal governments may still choose to seek TAS to develop a Tribal plan with respect to the obligations under this proposed rule, and this proposed determination does not preclude the tribes from taking such actions. The EPA will continue to consult with the government of the Ute Indian Tribe of the Uintah and Ouray Reservation, and any other tribe wishing to continue consultation, during the comment period for this proposal. The EPA invites comment on this proposed finding.

a. Indian Country Subject to State Implementation Planning Authority

Following the U.S. Supreme Court decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020), the Governor of the State of Oklahoma requested approval under Section 10211(a) of the Safe, Accountable, Flexible, Efficient Transportation Equity Act of 2005: A Legacy for Users, Public Law 109–59, 119 Stat. 1144, 1937 (August 10, 2005) (''SAFETEA''), to administer in certain areas of Indian country (as defined at 18 U.S.C. 1151) the State's environmental regulatory programs that were previously approved by the EPA for areas outside of Indian country. The State's request excluded certain areas of Indian country further described later. In addition, the State only sought approval to the extent that such approval is necessary for the State to administer a program in light of *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014).[91]

On October 1, 2020, the EPA approved Oklahoma's SAFETEA request to administer all the State's EPA-approved environmental regulatory programs, including the Oklahoma SIP, in the requested areas of Indian country.[92] As requested by Oklahoma, the EPA's approval under SAFETEA does not include Indian country lands, including rights-of-way running through the same, that: (1) Qualify as Indian allotments, the Indian titles to which have not been extinguished, under 18 U.S.C. 1151(c); (2) are held in trust by the United States on behalf of an individual Indian or Tribe; or (3) are owned in fee by a Tribe, if the Tribe (a) acquired that fee title to such land, or an area that included such land, in accordance with a treaty with the United States to which such Tribe was a party, and (b) never allotted the land to a member or citizen of the Tribe (collectively ''excluded Indian country lands'').

EPA's approval under SAFETEA expressly provided that to the extent EPA's prior approvals of Oklahoma's environmental programs excluded Indian country, any such exclusions are superseded for the geographic areas of Indian country covered by EPA's approval of Oklahoma's SAFETEA request.[93] The approval also provided that future revisions or amendments to Oklahoma's approved environmental regulatory programs would extend to the covered areas of Indian country (without any further need for additional requests under SAFETEA).

In a **Federal Register** notice published on February 22, 2022 (87 FR 9798), the EPA proposed to disapprove the portion of an Oklahoma SIP submittal pertaining to the state's interstate transport obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. Consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA* and with EPA's October 1, 2020 SAFETEA approval, if this disapproval is finalized as proposed, EPA will have authority under CAA section 110(c) to promulgate a FIP as needed to address the disapproved aspects of the State's good neighbor SIP submittal.[94] In accordance with the discussion above, EPA's FIP authority in this circumstance would extend to all Indian country in Oklahoma, other than the excluded Indian country lands, as described previously.[95] Because—per the State's request under SAFETEA—EPA's October 1, 2020 approval does not displace any SIP authority previously exercised by the State under the CAA as interpreted in *ODEQ* v. *EPA,* EPA's FIP authority under CAA section 110(c) would also apply to any Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority. EPA's FIP authority under CAA section 110(c) would similarly apply to Indian allotments or dependent Indian communities located outside of an Indian reservation over which there has been no demonstration of tribal authority located in any other state within the geographic scope of this proposed rule.

In light of the relevant legal authorities discussed above regarding the scope of the State of Oklahoma's regulatory jurisdiction under the CAA, the EPA has FIP authority under CAA section 110(c) with respect to all Indian country in Oklahoma other than excluded Indian country lands. To the extent any change occurs in the scope of Oklahoma's SIP authority in Indian country before the finalization of this proposed rule, such a change may affect the ability of the Agency to exercise the FIP authority provided under section 110(c) of the Act.[96] In that eventuality,

[91] In *ODEQ* v. *EPA,* the D.C. Circuit held that under the CAA, a state has the authority to implement a SIP in non-reservation areas of Indian country in the state, where there has been no demonstration of tribal jurisdiction. Under the D.C. Circuit's decision, the CAA does not provide authority to states to implement SIPs in Indian reservations. *ODEQ* did not, however, substantively address the separate authority in Indian country provided specifically to Oklahoma under SAFETEA. That separate authority was not invoked until the State submitted its request under SAFETEA, and was not approved until EPA's decision, described in this section, on October 1, 2020.

[92] Available in the docket for this rulemaking.

[93] EPA's prior approvals relating to Oklahoma's SIP frequently noted that the SIP was not approved to apply in areas of Indian country (consistent with the D.C. Circuit's decision in *ODEQ* v. *EPA*) located in the state. *See, e.g.,* 85 FR 20178, 20180 (April 10, 2020). Such prior expressed limitations are superseded by EPA's approval of Oklahoma's SAFETEA request.

[94] The antecedent fact that the state had the authority and jurisdiction to implement requirements under the good neighbor provision, in EPA's view, supplies the condition necessary for the Agency to exercise its FIP authority to the extent the EPA has disapproved the state's SIP submission with respect to those requirements. Under CAA section 110(c), the EPA ''stands in the shoes of the defaulting state, and all of the rights and duties that would otherwise fall to the state accrue instead to the EPA.'' *Central Ariz. Water Conservation Dist.* v. *EPA,* 990 F.2d 1531, 1541 (9th Cir. 1993).

[95] With respect to those areas of Indian country constituting ''excluded Indian country lands'' in the State of Oklahoma, as defined above, the EPA proposes to apply the same necessary or appropriate finding as set forth above with respect to all other 301(d) FIP areas within the geographic scope of coverage of the rule.

[96] On December 22, 2021, the EPA proposed to withdraw and reconsider the October 1, 2020, SAFETEA approval. *See https://www.epa.gov/ok/proposed-withdrawal-and-reconsideration-and-supporting-information.* The EPA is engaging in further consultation with tribal governments and expects to have discussions with the State of Oklahoma as part of this reconsideration. The EPA also notes that the October 1, 2020, approval is the

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and to the extent any such areas would then fall more appropriately within the 301(d) FIP areas as described earlier in this section, EPA's proposed necessary or appropriate finding as set forth above with respect to all other 301(d) FIP areas within the geographic scope of coverage of the rule would then apply.

V. Analyzing Downwind Air Quality Problems and Contributions From Upwind States

A. Selection of Analytic Years for Evaluating Ozone Transport Contributions to Downwind Air Quality Problems

In this section, the EPA describes its process for selecting analytic years for air quality modeling and analyses performed to identify nonattainment and maintenance receptors and identify upwind state linkages. For this proposed rule, the EPA evaluated air quality to identify receptors at Step 1 for three analytic years: 2023, 2026, and 2032. The EPA evaluated interstate contributions to these receptors from individual upwind states at Step 2 for two of these analytic years: 2023 and 2026. In selecting these years, the EPA views 2023 and 2026, in particular, to constitute years by which key emissions reductions from EGUs and non-EGUS can be implemented ''as expeditiously as practicable.'' (The EPA explains in detail in Section VII of this proposed rule its proposed determination that the necessary emissions reductions cannot be achieved any more quickly.) In addition, these years are the last full ozone seasons before the Moderate and Serious area attainment dates for the 2015 ozone NAAQS (ozone seasons run each year from May 1–September 30). In order to demonstrate attainment by these deadlines, downwind states would be required to rely on design values calculated using ozone design values from 2021 through 2023 and 2024 through 2026, respectively. By focusing its analysis, and, potentially, achieving emissions reductions by, the last full ozone seasons before the attainment dates (*i.e.,* in 2023 or 2026), this proposed rule, if finalized, can assist the downwind areas with demonstrating attainment or receiving extensions of attainment dates under CAA section 181(a)(5).

It would not make sense for the EPA to analyze any earlier year than 2023. EPA continues to interpret the good neighbor provision as forward-looking, based on Congress's use of the future-tense ''will'' in section 110(a)(2)(D)(i), an interpretation upheld in *Wisconsin,* 938 F.3d at 322. It would be ''anomalous,'' *id.,* for the EPA to impose good neighbor obligations in 2023 and future years based solely on finding that ''significant contribution'' had existed at some time in the past. *Id.*

Applying this framework in this proposal, the EPA recognizes that the 2021 Marginal area attainment date has already passed. Further, based on the timing of this proposal, it will not be possible to finalize this rulemaking before the 2022 ozone season has also passed. Thus, EPA has selected 2023 as the first appropriate future analytic year for this proposed rule because it reflects implementation of good neighbor obligations as expeditiously as practicable and coincides with the August 3, 2024, Moderate area attainment date established for the 2015 ozone NAAQS.

The EPA conducted additional analysis for the 2026 and 2032 analytic years in order to ensure a complete Step 3 analysis for future ozone transport contributions to downwind areas. These years also coincide with the last full ozone seasons before future attainment dates for the 2015 ozone NAAQS, and 2026 coincides with the ozone season by which key additional emissions reductions from EGUs and non-EGUs become available. Thus, the EPA analyzed additional years beyond 2023 to determine whether any additional emissions reductions that are impossible to obtain by the 2024 attainment date could still be necessary in order to fully address significant contribution, taking into account the 2027 Serious area attainment date and the 2033 Severe area attainment date for the 2015 ozone NAAQS. In all cases, the proposed implementation of necessary emissions reductions is as expeditiously as practicable, with all possible emissions reductions implemented by the next applicable attainment date.

The timing framework and selection of analytic years set forth above comports with the D.C. Circuit's direction in *Wisconsin* that implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity. *See* 938 F.3d at 320.

The remainder of this section includes information on (1) the air quality modeling platform used in support of the proposed rule with a focus on the base year and future year base case emissions inventories, (2) the method for projecting design values in 2023, 2026, and 2032, and (3) the approach for calculating ozone contributions from upwind states. The Agency also provides the design values for nonattainment and maintenance receptors and the predicted interstate contributions that are at or above the 1 percent of the NAAQS screening threshold. The 2016 base period and 2023, 2026, and 2032 future design values and contributions for all ozone monitoring sites are provided in the docket for this proposed rule. The Air Quality Modeling Technical Support Document (AQM TSD) in the docket for this proposed rule contains more detailed information on the air quality modeling aspects of this rule.

B. Overview of Air Quality Modeling Platform

The EPA used version 2 of the 2016-based modeling platform for the air quality modeling for this proposed rule. This modeling platform includes 2016 base year emissions from anthropogenic and natural sources and 2016 meteorology. The platform also includes anthropogenic emissions projections for 2023, 2026, and 2032. The emissions data contained in this platform represent an update to the 2016 version 1 inventories that were developed by the EPA, the Multi-Jurisdictional Organizations (MJOs), and state and local air agencies as part of the Emissions Inventory Collaborative Process.

The air quality modeling for this proposal was performed for a modeling region (*i.e.,* modeling domain) that covers the contiguous 48 states using a horizontal resolution of 12 x 12 km. The EPA used the CAMx version 7.10 for air quality modeling since this was the most recent version of CAMx available at the time the air quality modeling was performed.[97] Additional information on the 2016-based air quality modeling platform can be found in the AQM TSD.

C. Emissions Inventories

The EPA developed emissions inventories for this proposal, including emissions estimates for EGUs, non-EGU point sources, stationary nonpoint sources, onroad mobile sources, nonroad mobile sources, other mobile sources, wildfires, prescribed fires, and biogenic emissions that are not the direct result of human activities. EPA's air quality modeling relies on this comprehensive set of emissions inventories because emissions from multiple source categories are needed to model ambient air quality and to facilitate comparison of model outputs with ambient measurements.

subject of a pending challenge in federal court. *Pawnee Nation of Oklahoma* v. *Regan,* No. 20–9635 (10th Cir.).

[97] Ramboll Environment and Health, January 2021, *http://www.camx.com.*

To prepare the emissions inventories for air quality modeling, the EPA processed the emissions inventories using the Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System version 4.8.1 to produce the gridded, hourly, speciated, model-ready emissions for input to the air quality model. Additional information on the development of the emissions inventories and on data sets used during the emissions modeling process are provided in the TSD titled, ''Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform,'' hereafter known as the ''Emissions Modeling TSD.'' This TSD is available in the docket for this rule.

1. Foundation Emissions Inventory Data Sets

The 2016v2 emissions platform is comprised of data from various sources including data developed using models, methods, and source datasets that became available in calendar years 2020 and 2021, in addition to data from the Inventory Collaborative 2016 version 1 (2016v1) Emissions Modeling Platform, released in October 2019. The 2016v1 platform was developed through a national collaborative effort between the EPA and state and local agencies along with MJOs and included emissions inventories for the years 2016, 2023, and 2028. For this proposed rule, emissions inventories were developed for the years 2016, 2023, 2026, and 2032 that represent changes in activity data and of predicted emissions reductions from on-the-books actions, planned emissions control installations, and promulgated federal measures that affect anthropogenic emissions.[98] The 2016 emissions inventories for the U.S. include data derived from the 2017 National Emissions Inventory (2017NEI) and some data derived from the 2014 National Emissions Inventory (NEI), version 2 (2014NEIv2). All of the inventory sectors were updated to better represent the year 2016 through the incorporation of 2016-specific state and local data along with nationally applied adjustment methods. The following sections provide an overview of the construct of the 2016v2 emissions and projections.

2. Development of Emissions Inventories for EGUs

Annual NO_X and SO_2 emissions for EGUs in the 2016 base year inventory are based primarily on data from continuous emissions monitoring systems (CEMS) and other monitoring systems allowed for use by qualifying units under 40 CFR part 75, with other EGU pollutants estimated using emissions factors and annual heat input data reported to the EPA. For EGUs not reporting under part 75, the EPA used data submitted to the NEI and the 2016v1 platform by the states. Emissions data for EGUs that did not have data provided for the year 2016 were pulled forward from data submitted for the 2014 NEI. The Air Emissions Reporting Rule, (80 FR 8787; February 19, 2015), requires that Type A point sources large enough to meet or exceed specific thresholds for emissions be reported to the EPA every year, while the smaller Type B point sources must only be reported to EPA every 3 years.

The EPA projected future 2023, 2026, and 2032 baseline EGU emissions using the version 6—Summer 2021 Reference Case of the Integrated Planning Model (IPM). IPM, developed by ICF Consulting, is a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. The EPA has used IPM for over two decades, including all prior implemented CSAPR rulemakings, to better understand power sector behavior under future business-as-usual conditions and to evaluate the economic and emissions impacts of prospective environmental policies. The model is designed to reflect electricity markets as accurately as possible. The EPA uses the best available information from utilities, industry experts, gas and coal market experts, financial institutions, and government statistics as the basis for the detailed power sector modeling in IPM. The model documentation provides additional information on the assumptions discussed here as well as all other model assumptions and inputs.[99]

The IPM version 6—Summer 2021 Reference Case incorporated recent updates through the Summer of 2021 to account for updated federal and state environmental regulations (including Renewable Portfolio Standards (RPS), Clean Energy Standards (CES) and other state mandates), fleet changes (committed EGU retirements and new builds), electricity demand, technology cost and performance assumptions from recent data (for renewables adopting from National Renewable Energy Lab (NREL's) Annual Technology Baseline 2020 and for fossil sources from U.S. Energy Information Agency's (EIA) Annual Energy Outlook (AEO) 2020. Natural gas and coal price projections reflect data developed in Fall 2020. The inventory of EGUs provided as an input to the model was the National Electric Energy Data System (NEEDS) Summer 2021 version and is available on EPA's website.[100] This version of NEEDS reflects announced retirements and under construction new builds known as of early summer 2021. This projected base case accounts for the effects of the finalized Mercury and Air Toxics Standards rule, CSAPR, the CSAPR Update, the Revised CSAPR Update, New Source Review settlements, the final Effluent Limitation Guidelines (ELG) Rule, the Coal Combustion Residual (CCR) Rule, and other on-the-books federal and state rules (including renewable energy tax credit extensions from the Consolidated Appropriations Act of 2021) through early 2021 impacting SO_2, NO_X, directly emitted particulate matter, CO_2, and power plant operations. It also includes final actions the EPA has taken to implement the Regional Haze Rule and BART requirements. IPM has projected output years for 2023 and 2025. IPM year 2025 outputs were adjusted for known retirements to be reflective of year 2026, and IPM year 2030 outputs were used for the year 2032 as is specified by the mapping of IPM output years to specific years.

Additional 2023 through 2026 EGU emissions baseline levels were developed through engineering analytics as an alternative approach that did not involve IPM. The EPA developed this inventory for use in Step 3 of this final rule, where it determines emissions reduction potential and corresponding state-level emissions budgets. IPM includes optimization and perfect foresight in solving for least cost dispatch. Given that this final rule will likely become effective immediately prior to the start of the 2023 ozone season, the EPA is adopting a similar approach to the CSAPR Update and the

[98] Biogenic emissions and emissions from wildfires and prescribed fires were held constant between 2016 and the future years because (1) these emissions are tied to the 2016 meteorological conditions and (2) the focus of this rule is on the contribution from anthropogenic emissions to projected ozone nonattainment and maintenance.

[99] Detailed information and documentation of EPA's Base Case, including all underlying assumptions, data sources, and architecture parameters can be found on EPA's website at: *https://www.epa.gov/airmarkets/epas-power-sector-modeling-platform-v6-using-ipm-summer-2021-reference-case.*

[100] *Available at https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

Revised CSAPR Update where it relied on IPM in a relative way in Step 3 to avoid overstating optimization and dispatch decisions in state-emissions budget quantification that may not be possible in a short time frame. The EPA does this by using the difference in emissions rate observed between IPM runs with and without the cost threshold applied, rather than using absolute values. In both the CSAPR Update and in this rule at Step 3, EPA complemented that projected IPM EGU outlook with historical (*e.g.,* engineering analytics) perspective based on historical data that only factors in known changes to the fleet. This 2023 engineering analytics data set is described in more detail in the Ozone Transport Policy Analysis Proposed Rule TSD and corresponding Appendix A: State Emissions Budgets Calculations and Underlying Data. The Engineering Analysis used in Step 3 is also discussed further in Section VII.B of this proposed rule.

Both IPM and the Engineering Analytics tools are valuable for estimating future EGU emissions and examining the cone of uncertainty around any future sector-level inventory estimate. A key difference between the two tools is that IPM reflects both announced and projected changes in fleet operation, whereas the Engineering Analytics tool only reflects announced changes. By not including projected changes that are anticipated in response to market forces and fleet trends, the Engineering Analysis is deliberately conservative in its estimate of change in the power sector. Throughout all of the CSAPR rules to date, and prior interstate transport actions, the EPA has used IPM at Steps 1 and 2 as it is best suited for projecting emissions in an airshed, at projecting emissions for time horizons more than a few years out (for which changes would not yet be announced and thus projecting changes is critical), and for scenarios where the assumed change in emissions is not being codified into a state emissions reduction requirement. Using IPM at Steps 1 and 2 helps the EPA avoid overstating future year receptor values (Step 1) and future year linkages (Step 2) by reflecting reductions anticipated to occur within the airshed in the relevant timeframe.

Engineering analytics has been a useful tool for Step 3 state-level emissions reduction estimates in CSAPR rulemaking, because at that step EPA is dealing with more geographic granularity (state-level as opposed to regional air shed), more near-term (as opposed to medium-term) assessments, and scenarios where reduction estimates are codified into regulatory requirements. Using the Engineering Analytics tool at this step ensures that the EPA is not codifying into the base case, and consequently into state emissions budgets, changes in the power sector that are merely modeled to occur rather than announced by real-world actors.

Finally, both in the Revised CSAPR Update and in this rule, the EPA was able to use the Air Quality Assessment Tool to verify that regardless of which EGU inventory is used, the 2023 starting geography of the program is not impacted. In other words, regardless of whether a stakeholder takes a more comprehensive view of the EGU future (IPM) or a more conservative view of change in the EGU fleet (Engineering Analysis) the starting geography would be the same. This finding is consistent with the observation that EGUs are now less than 10% of the total ozone-season NO_X inventory and the degree of near-term difference between the IPM and Engineering Analytic regional projections is relatively small on the regional level. While the EPA continues to believe that IPM is best suited for Step 1 and Step 2, and engineering analytics is best suited for Step 3 efforts in this rulemaking, the Agency is requesting comment on the EGU emissions inventory most reasonable for Step 1 and Step 2 in the analysis. The Ozone Transport Policy Analysis Proposed Rule TSD contains data on 2023 and 2026 AQ impacts of each dataset.

3. Development of Emissions Inventories for Non-EGU Point Sources

The updates to the non-EGU point source emissions include a few sources being moved to the EGU inventory and additional control efficiency information for the year 2016. In the 2016v2 platform, some non-EGU point source emissions were based on data submitted for 2016, others were projected from 2014 to 2016, and the emissions for any remaining small sources were kept at 2014 levels. Prior to air quality modeling, the emissions inventories were processed into a format that is appropriate for the air quality model to use. The future year non-EGU point inventories were grown from 2016 to the future years using factors based on the AEO 2021 except for limited cases where errors were identified with the AEO 2021 data in which case data from AEO 2020 were used. The future year inventories reflect emissions reductions due to national and local rules, control programs, plant closures, consent decrees, and settlements. Reductions from several Maximum Achievable Control Technology and National Emissions Standards for Hazardous Air Pollutants (NESHAP) standards are included. Projection approaches for corn ethanol and biodiesel plants, refineries and upstream impacts represent requirements pursuant to the Energy Independence and Security Act of 2007 (EISA).

Aircraft emissions and ground support equipment at airports are represented as point sources and are based on adjustments to emissions in the January 2021 version of the 2017 NEI (see *https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data* for data and a TSD). A notable update in the January 2021 version of the 2017 NEI as compared to the April 2020 version was a correction to some double counting of some airport emissions. This correction is incorporated into the inventories for this proposed rule. The EPA developed and applied factors to adjust the 2017 airport emissions to 2016, 2023, 2026, and 2032 based on activity growth projected by the Federal Aviation Administration 2019 Terminal Area Forecast [101] system, the latest available version at the time the factors were developed.

Emissions at rail yards were represented as point sources. The 2016 rail yard emissions are largely consistent with the 2017 NEI rail yard emissions. The 2016 and 2023 rail yard emissions were developed through the 2016v1 Inventory Collaborative process, with the 2026 emissions interpolated between the 2023 and 2028 emissions from 2016v1 rail yard emissions were interpolated from the 2016 and 2023 emissions. Class I rail yard emissions were projected based on the AEO freight rail energy use growth rate projections for 2016, 2023, and 2032 with the fleet mix assumed to be constant throughout the period.

Point source oil and gas emissions for 2016 were based on the 2016v1 point inventory except that an inventory generated by the Western Regional Air Partnership (WRAP) [102] was used for the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming. The 2016 oil and gas inventories were first projected to 2019 values based on actual production data, and those 2019 emissions were projected to 2023, 2026, and 2032 using regional projection factors by product type based on AEO 2021 projections. NO_X and VOC reductions that are co-

[101] *https://www.faa.gov/data_research/aviation/taf/.*

[102] *http://www.wrapair2.org/pdf/WRAP_OGWG_Report_Baseline_17Sep2019.pdf.*

benefits to the NESHAP and New Source Performance Standards (NSPS) for Stationary Reciprocating Internal Combustion Engines (RICE) are reflected for select source categories. In addition, Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls [103] are reflected for select source categories. The WRAP future year inventory was used in WRAP states in all future years.[104]

4. Development of Emissions Inventories for Onroad Mobile Sources

Onroad mobile sources include exhaust, evaporative, and brake and tire wear emissions from vehicles that drive on roads, parked vehicles, and vehicle refueling. Emissions from vehicles using regular gasoline, high ethanol gasoline, diesel fuel, and electric vehicles were represented, along with buses that used compressed natural gas. The EPA developed the onroad mobile source emissions for states other than California using EPA's Motor Vehicle Emissions Simulator (MOVES). MOVES3 was released in November 2020 and has been followed by some minor releases that improved the usage of the model but that do not have substantive impacts on the emissions estimates. For this proposal, MOVES3 was run using inputs provided by state and local agencies through the 2017 NEI where available, in combination with nationally available data sets to develop a complete inventory. Onroad emissions for 2016v2 were developed based on emissions factors output from MOVES3 run for the year 2016, coupled with activity data (*e.g.,* vehicle miles traveled and vehicle populations) representing the year 2016. The 2016 activity data were provided by some state and local agencies through the 2016v1 process, and the remaining activity data were derived from the 2017 NEI. The onroad emissions were computed within SMOKE by multiplying emissions factors developed using MOVES with the appropriate activity data. Onroad mobile source emissions for California were consistent with the emissions data provided by the state.

The future-year emissions estimates for onroad mobile sources represent all national control programs known at the time of modeling including rules newly added in MOVES3: The Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (HDGHG)—Phase 2 [105] and the Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule.[106] Other finalized rules incorporated into the onroad mobile source emissions estimates include: Tier 3 Standards (March 2014), the Light-Duty Greenhouse Gas Rule (March 2013), Heavy (and Medium)-Duty Greenhouse Gas Rule (August 2011), the Renewable Fuel Standard (February 2010), the Light Duty Greenhouse Gas Rule (April 2010), the Corporate-Average Fuel Economy standards for 2008–2011 (April 2010), the 2007 Onroad Heavy-Duty Rule (February 2009), and the Final Mobile Source Air Toxics Rule (MSAT2) (February 2007). Estimates of the impacts of rules that were in effect in 2016 are included in the 2016 base year emissions at a level that corresponds to the extent to which each rule had penetrated into the fleet and fuel supply by the year 2016. Local control programs such as the California LEV III program for criteria pollutants are included in the onroad mobile source emissions.

The future year onroad emissions reflect projected changes to fuel properties and usage, along with the impact of the rules included in MOVES3 for each of the future years. MOVES was run for the years 2023, 2026, and 2032 to generate the emissions factors relevant to those years. Future year activity data for onroad mobile sources were provided by some state and local agencies, and otherwise were projected to 2023, 2026, and 2032 by first projecting the 2016 activity to year 2019 based on county level vehicle miles traveled (VMT) from the Federal Highway Administration, and then from 2019 to the future years using AEO 2021-based factors. The future year emissions were computed within SMOKE by multiplying the future year emissions factors developed using MOVES with the year-specific activity data.

5. Development of Emissions Inventories for Commercial Marine Vessels

The commercial marine vessel (CMV) emissions in the 2016 base case emissions inventory for this rule were based on those in the 2017 NEI. Factors were then applied to adjust the 2017 NEI emissions backward to represent emissions for the year 2016. The CMV emissions reflect reductions associated with the Emissions Control Area proposal to the International Maritime Organization control strategy (EPA–420–F–10–041, August 2010); reductions of NO_X, VOC, and CO emissions for new C3 engines that went into effect in 2011; and fuel sulfur limits that went into effect prior to 2016. The cumulative impacts of these rules through 2023, 2026 and 2030 [107] were incorporated into the projected emissions for CMV sources. The CMV emissions were split into emissions inventories from the larger category 3 (C3) engines, and those from the smaller category 1 and 2 (C1C2) engines. CMV emissions in California are based on emissions provided by the state. The CMV emissions are consistent with the emissions for the 2016v1 platform updated CMV emissions released by February 2020 although they include future years of 2026 and 2030 instead of 2028.

6. Development of Emissions Inventories for Other Nonroad Mobile Sources

Nonroad mobile source emissions inventories (other than CMV, locomotive, and aircraft emissions) were developed from monthly, county, and process level emissions output from MOVES3. Types of nonroad equipment include recreational vehicles, pleasure craft, and construction, agricultural, mining, and lawn and garden equipment. State-submitted emissions data for nonroad sources were used for California.

The EPA also ran MOVES3 for 2023, 2026, and 2032 to prepare nonroad mobile emissions inventories for future years. The nonroad mobile emissions control programs include reductions to locomotives, diesel engines, and recreational marine engines, along with standards for fuel sulfur content and evaporative emissions. A comprehensive list of control programs included for mobile sources is available in the Emissions Modeling TSD.

[103] On November 15, 2021, the EPA published proposed revisions to standards of performance for new, reconstructed, and modified sources and proposed revisions to emissions guidelines for existing sources in the oil and natural gas sector at 86 FR 63110. Emissions reductions from proposed federal regulatory programs are not included in EPA's baseline analyses until they have been finalized.

[104] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[105] The effect of the HDGHG Phase 2 rule on criteria pollutants is estimated in Table 5–48 of the Regulatory Impact Analysis, available from *https://nepis.epa.gov/Exe/ZyPDF.cgi/P100P7NS.PDF?Dockey=P100P7NS.PDF.*

[106] Information on the SAFE vehicles rule is available from *https://www.epa.gov/regulations-emissions-vehicles-and-engines/safer-affordable-fuel-efficient-safe-vehicles-final-rule.* Preliminary analysis by the Office of Transportation and Air Quality of the impact of this rule on criteria pollutants show impacts of less than 1 percent for VOC and no impact for NO_X.

[107] CMV emissions were projected out to 2030 instead of 2032 because that was the last year of data available in a dataset used in the projections process. The year 2030 inventories were used in the 2032 emissions case.

Line haul locomotives are also considered a type of nonroad mobile source but the emissions inventories for locomotives were not developed using MOVES3. Year 2016 and 2023 locomotive emissions were developed through the 2016v1 process and the year 2016 emissions are mostly consistent with those in the 2017 NEI. The projected locomotive emissions for 2023, 2026, and 2030[108] were developed by applying factors to the base year emissions using activity data based on AEO freight rail energy use growth rate projections along with emissions rates adjusted to account for recent historical trends.

7. Development of Emissions Inventories for Nonpoint Sources

Some emissions for stationary nonpoint sources in the 2016 base case emissions inventory come from the 2017 NEI adjusted to 2016 levels, while others are based on data from the 2014NEIv2 adjusted to reflect year 2016 more closely using factors based on changes to human population from 2014 to 2016. Stationary nonpoint sources include evaporative sources, consumer products, fuel combustion that is not captured by point sources, agricultural livestock, agricultural fertilizer, residential wood combustion, fugitive dust, and oil and gas sources. The emissions sources based on the 2017 NEI include agricultural livestock, fugitive dust, residential wood combustion, waste disposal (including composting), bulk gasoline terminals, and miscellaneous non-industrial sources such as cremation, hospitals, lamp breakage, and automotive repair shops. A new method for solvent VOC emissions was used.[109]

Where states provided the Inventory Collaborative information about projected control measures or changes in nonpoint source emissions for 2016v1 or 2016v2, those inputs were incorporated into the projected inventories for 2023, 2026, and 2032 to the extent possible. Where possible, projection factors based on the AEO were based on AEO 2021. Adjustments for state fuel sulfur content rules for fuel oil in the Northeast were included. Projected emissions for portable fuel containers reflect the impact of projection factors required by the final MSAT2 rule and the EISA, including updates to cellulosic ethanol plants, ethanol transport working losses, and ethanol distribution vapor losses.

For 2016, nonpoint oil and gas emissions inventories were developed based on a run of the 2017 NEI version of the EPA Oil and Gas Tool with data for year 2016 coupled with the WRAP inventory for production-related nonpoint oil and gas emissions in the states of Colorado, Montana, New Mexico, North Dakota, South Dakota, Utah, and Wyoming, and a California Air Resources Board-provided inventory was used for emissions in California. Nonpoint oil and gas emissions in other states and exploration-related emissions in the WRAP states were based on a run of the 2017 NEI version of the EPA Oil and Gas Tool with input data for the year 2016. The 2016 oil and gas inventories were first projected to 2019 values based on actual production data, and those 2019 emissions were projected to 2023, 2026, and 2032 using regional projection factors by product type based on AEO 2021 projections. NO_X and VOC reductions that are co-benefits to the NESHAP and NSPS for RICE are reflected for select source categories. In addition, Natural Gas Turbines and Process Heaters NSPS NO_X controls and NSPS Oil and Gas VOC controls are reflected for select source categories. The WRAP future year inventory was used in WRAP states in all future years.[110]

D. Air Quality Modeling To Identify Nonattainment and Maintenance Receptors

In this section, the Agency describes the air quality modeling and analyses performed in Step 1 to identify locations where the Agency expects there to be nonattainment or maintenance receptors for the 2015 ozone NAAQS in the 2023, 2026, and 2032 analytic future years. Where EPA's analysis shows that an area or site does not fall under the definition of a nonattainment or maintenance receptor in 2023, that site is excluded from further analysis under EPA's good neighbor framework.

In this proposed rule, the EPA is applying the same approach used in the CSAPR Update and the Revised CSAPR Update to identify nonattainment and maintenance receptors for the 2008 ozone NAAQS. *See* 86 FR 23078–79.

EPA's approach gives independent effect to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina.*[111] Further, in its decision on the remand of the CSAPR from the Supreme Court in the *EME Homer City* case, the D.C. Circuit confirmed that EPA's approach to identifying maintenance receptors in the CSAPR comported with the court's prior instruction to give independent meaning to the ''interfere with maintenance'' prong in the good neighbor provision. *EME Homer City II,* 795 F.3d at 136.

In the CSAPR Update and the Revised CSAPR Update, the EPA identified nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the NO_X SIP Call and CAIR, where the EPA defined nonattainment receptors as those areas that both currently monitor nonattainment and that the EPA projects will be in nonattainment in the future compliance year.[112]

The Agency explained in the NO_X SIP Call and CAIR and then reaffirmed in the CSAPR Update that the EPA has the most confidence in our projections of nonattainment for those counties that also measure nonattainment for the most recent period of available ambient data. The EPA separately identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that accounts for historical variability in air quality at that receptor. The variability in air quality was determined by evaluating the ''maximum'' future design value at each receptor based on a projection of the maximum measured design value over the relevant period. The EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). The EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, and air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the

[108] The farthest out year for which locomotive emissions were projected was 2030 and those were used in the 2032 case.

[109] *https://doi.org/10.5194/acp-21-5079-2021.*

[110] *http://www.wrapair2.org/pdf/WRAP_OGWG_2028_OTB_RevFinalReport_05March2020.pdf.*

[111] 531 F.3d at 910–911 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[112] *See* 63 FR 57375, 57377 (October 27, 1998); 70 FR 25241(January 14, 2005). *See also North Carolina,* 531 F.3d at 913–914 (affirming as reasonable EPA's approach to defining nonattainment in CAIR).

future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur.[113] The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

Therefore, applying this methodology in this proposed rule, EPA assessed the magnitude of the maximum projected design values for 2023, 2026, and 2032 at each receptor in relation to the 2015 ozone NAAQS and, where such a value exceeds the NAAQS, the EPA determined that receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City II.*[114] That is, monitoring sites with a maximum design value that exceeds the NAAQS are projected to have maintenance problems in the future analytic years.[115]

Recognizing that nonattainment receptors are also, by definition, maintenance receptors, the EPA often uses the term ''maintenance-only'' to refer to receptors that are not also nonattainment receptors. Consistent with the concepts for maintenance receptors, as described above, the EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values. In addition, those monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance only'' receptors, even if they are currently measuring nonattainment based on the most recent official design values.

Consistent with EPA's modeling guidance, the 2016 base year and future year air quality modeling results were used in a relative sense to project design values for 2023, 2026, and 2032. That is, the ratios of future year model predictions to base year model predictions are used to adjust ambient ozone design values[116] up or down depending on the relative (percent) change in model predictions for each location. The modeling guidance recommends using measured ozone concentrations for the 5-year period centered on the base year as the air quality data starting point for future year projections. This average design value is used to dampen the effects of inter-annual variability in meteorology on ozone concentrations and to provide a reasonable projection of future air quality at the receptor under average conditions. In addition, the Agency calculated maximum design values from within the 5-year base period to represent conditions when meteorology is more favorable than average for ozone formation. Because the base year for the air quality modeling used in this proposed rule is 2016, measured data for 2014–2018 (*i.e.,* design values for 2016, 2017, and 2018) were used in order to project average and maximum design values in 2023, 2026, and 2032.

The ozone predictions from the 2016 and future year air quality model simulations were used to project 2016–2018 average and maximum ozone design values to 2023, 2026, and 2032 using an approach similar to the approach in EPA's guidance for attainment demonstration modeling. This guidance recommends using model predictions from the 3 x 3 array of grid cells[117] surrounding the location of the monitoring site to calculate a Relative Response Factor (RRF) for that site.[118] The 2016–2018 base period average and maximum design values were multiplied by the RRF to project each of these design values to each of the three future years. In this manner, the projected design values are grounded in monitored data, and not the absolute model-predicted future year concentrations. Following the approach in the CSAPR Update and the Revised CSAPR Update, the EPA also projected future year design values based on a modified version of the ''3 x 3'' approach for those monitoring sites located in coastal areas. In this alternative approach, EPA eliminated from the RRF calculations the modeling data in those grid cells that are dominated by water (*i.e.,* more than 50 percent of the area in the grid cell is water) and that do not contain a monitoring site (*i.e.,* if a grid cell is more than 50 percent water but contains an air quality monitor, that cell would remain in the calculation). The choice of more than 50 percent of the grid cell area as water as the criteria for identifying overwater grid cells is based on the treatment of land use in the Weather Research and Forecasting model (WRF).[119] Specifically, in the WRF meteorological model those grid cells that are greater than 50% overwater are treated as being 100 percent overwater. In such cases the meteorological conditions in the entire grid cell reflect the vertical mixing and winds over water, even if part of the grid cell also happens to be over land with land-based emissions, as can often be the case for coastal areas. Overlaying land-based emissions with overwater meteorology may be representative of conditions at coastal monitors during times of on-shore flow associated with synoptic conditions or sea-breeze or lake-breeze wind flows. But there may be other times, particularly with off-shore wind flow, when vertical mixing of land-based emissions may be too

[113] The EPA's air quality modeling guidance identifies the use of the highest of the relevant base period design values as a means to evaluate future year attainment under meteorological conditions that are especially conducive to ozone formation. *See* U.S. Environmental Protection Agency, 2018. Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5,}$ and Regional Haze, Research Triangle Park, NC.

[114] *See* 795 F.3d at 136.

[115] The EPA issued a memorandum in October 2018, providing additional information to states developing interstate transport SIP submissions for the 2015 8-hour ozone NAAQS concerning considerations for identifying downwind areas that may have problems maintaining the standard at Step 1 of the 4-step interstate transport framework. *See* Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018 (''October 2018 memorandum''), available in Docket No. EPA–HQ–OAR–2021–0663 or at *https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs.* The EPA does not propose to adopt the information or suggested analytical approaches in that memorandum in this proposed rule proposing FIPs. Potential alternative approaches would introduce unnecessary and substantial additional analytical burdens that could frustrate timely and efficient implementation of good neighbor obligations. In addition, the information supplied in that memorandum is now outdated due to several additional years of air quality monitoring data and updated modeling results. EPA's current approach to defining ''maintenance'' receptors has been upheld and continues to provide an appropriate approach to addressing the ''interference with maintenance'' prong of the Good Neighbor provision. *See EME Homer City,* 795 F.3d 118, 136–37; *Wisconsin,* 938 F.3d at 325–26.

[116] The ozone design value at a particular monitoring site is the 3-year average of the annual 4th highest daily maximum 8-hour ozone concentration at that site.

[117] As noted above, each model grid cell is 12 x 12 km.

[118] The relative response factor represents the change in ozone at a given site. In order to calculate the RRF, EPA's modeling guidance recommends selecting the 10 highest ozone days in an ozone season at a given monitor in the base year, noting which of the grid cells surrounding the monitor experienced the highest ozone concentrations in the base year, and averaging those ten highest concentrations. The model is then run using the projected year emissions, in this case 2023, with all other model variables held constant. Ozone concentrations from the same ten days, in the same grid cells, are then averaged. The fractional change between the base year (2016 model run) averaged ozone concentrations and the future year (*e.g.,* 2023 model run) averaged ozone concentrations represents the relative response factor.

[119] *https://www.mmm.ucar.edu/weather-research-and-forecasting-model.*

limited due to the presence of overwater meteorology. Thus, for our modeling EPA projected average and maximum design values at individual monitoring sites based on both the ''3 x 3'' approach as well as the alternative approach that eliminates overwater cells in the RRF calculation for near-coastal areas (*i.e.,* ''no water'' approach). The projected 2023, 2026, and 2032 design values using both the ''3 x 3'' and ''no-water'' approaches are provided in the docket for this proposed rule. For this proposed rule, the EPA is relying upon design values based on the ''no water'' approach for identifying nonattainment and maintenance receptors.[120]

Consistent with the truncation and rounding procedures for the 8-hour ozone NAAQS, the projected design values are truncated to integers in units of ppb.[121] Therefore, projected design values that are greater than or equal to 71 ppb are considered to be violating the 2015 ozone NAAQS. For those sites that are projected to be violating the NAAQS based on the average design values in the future analytic years, the Agency examined the measured design values for 2020, which are the most recent official measured design values at the time of this proposal. As noted earlier, the Agency proposes to identify nonattainment receptors in this rulemaking as those sites that are violating the NAAQS based on current measured air quality and also have projected average design values of 71 ppb or greater. Maintenance-only receptors include both (1) those sites with projected average design values above the NAAQS that are currently measuring clean data and (2) those sites with projected average design values below the level of the NAAQS, but with projected maximum design values of 71 ppb or greater. In addition to the maintenance-only receptors, the 2021 ozone nonattainment receptors are also maintenance receptors because the maximum design values for each of these sites is always greater than or equal to the average design value. The monitoring sites that the Agency projects to be nonattainment and maintenance receptors for the ozone NAAQS in the 2023 and 2026 base case are used for assessing the contribution of emissions in upwind states to downwind nonattainment and maintenance of ozone NAAQS as part of this proposal.

Table V.D–1 contains the 2016-centered[122] base period average and maximum 8-hour ozone design values, the 2023 base case average and maximum design values and the 2020 design values for the sites that are projected to be nonattainment receptors in 2023. Table V.D–2 contains this same information for monitoring sites that are projected to be maintenance-only receptors in 2023. The design values for all monitoring sites in the U.S. are provided in the docket for this rule. Additional details on the approach for projecting average and maximum design values are provided in the AQM TSD.

TABLE V.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS *

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
060170010	CA	El Dorado	85.3	88	76.3	78.7	84
060170020	CA	El Dorado	82.0	84	74.3	76.2	80
060190007	CA	Fresno	87.0	89	80.4	82.2	80
060190011	CA	Fresno	90.0	91	82.9	83.8	84
060190242	CA	Fresno	84.3	86	79.5	81.1	79
060194001	CA	Fresno	90.3	92	82.8	84.4	81
060195001	CA	Fresno	91.0	94	83.7	86.4	84
060250005	CA	Imperial	76.7	77	76.3	76.6	78
060251003	CA	Imperial	76.0	76	75.4	75.4	68
060290007	CA	Kern	87.7	89	82.8	84.0	93
060290008	CA	Kern	83.0	85	79.1	81.0	85
060290011	CA	Kern	83.3	85	78.8	80.4	86
060290014	CA	Kern	86.0	88	81.3	83.2	85
060290232	CA	Kern	79.3	82	74.9	77.5	83
060292012	CA	Kern	89.3	90	84.1	84.7	85
060295002	CA	Kern	87.3	89	82.4	84.0	89
060296001	CA	Kern	80.7	81	77.1	77.4	82
060311004	CA	Kings	83.3	84	76.9	77.6	80
060370002	CA	Los Angeles	94.3	99	88.0	92.4	97
060370016	CA	Los Angeles	100.0	103	93.4	96.2	107
060371201	CA	Los Angeles	88.3	91	82.7	85.3	92
060371602	CA	Los Angeles	75.7	76	73.6	73.9	78
060371701	CA	Los Angeles	92.0	95	85.6	88.4	88
060372005	CA	Los Angeles	84.7	86	80.7	81.9	93
060376012	CA	Los Angeles	98.0	100	91.6	93.4	101
060379033	CA	Los Angeles	87.3	89	80.7	82.2	80
060390004	CA	Madera	80.3	83	75.7	78.3	76
060392010	CA	Madera	82.7	84	77.0	78.2	78
060430003	CA	Mariposa	76.0	79	74.2	77.1	79
060470003	CA	Merced	80.7	82	74.7	75.9	76
060570005	CA	Nevada	86.3	90	78.1	81.5	82

[120] Using design values from the ''3 x 3'' approach, the maintenance-only receptor at site 170317002 in Cook County, IL would become a nonattainment receptor because the average design value with the ''3 x 3'' approach is 71.1 ppb versus 70.1 ppb with the ''no water'' approach. In addition, the monitor at site 170971007 in Lake County, IL which was not projected to be a receptor using the ''no water'' approach would be a maintenance-only receptor with the ''3 x 3'' approach because the maximum design value with the ''no water'' approach was 69.9 ppb versus a maximum design value of 71.2 ppb with the ''3 x 3'' approach. However, including this Lake County, Illinois site as a receptor would not affect which states are covered by this proposed rule.

[121] 40 CFR part 50, Appendix P to Part 50—Interpretation of the Primary and Secondary National Ambient Air Quality Standards for Ozone.

[122] 2016-centered averaged design values represent the average of the design values for 2016, 2017, and 2018. Similarly, the maximum 2016-centered design value is the highest measured design value from these three design value periods.

TABLE V.D–1—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED NONATTAINMENT RECEPTORS *—Continued

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
060592022	CA	Orange	77.7	78	72.5	72.8	82
060595001	CA	Orange	75.3	76	72.3	73.0	77
060610003	CA	Placer	85.0	88	77.1	79.8	N/A
060610004	CA	Placer	79.3	85	71.9	77.0	N/A
060610006	CA	Placer	80.0	81	72.8	73.7	72
060650008	CA	Riverside	76.5	79	71.0	73.3	N/A
060650012	CA	Riverside	95.3	98	85.9	88.3	99
060650016	CA	Riverside	79.0	80	72.0	72.9	78
060651016	CA	Riverside	99.7	101	89.8	90.9	99
060652002	CA	Riverside	82.7	85	76.4	78.5	84
060655001	CA	Riverside	88.7	91	80.5	82.6	88
060656001	CA	Riverside	92.3	93	83.5	84.1	94
060658001	CA	Riverside	96.7	98	89.5	90.7	96
060658005	CA	Riverside	95.0	98	87.9	90.7	98
060659001	CA	Riverside	88.7	91	80.8	82.9	87
060670002	CA	Sacramento	77.7	78	71.4	71.7	72
060670012	CA	Sacramento	82.3	83	74.8	75.4	N/A
060710001	CA	San Bernardino	79.0	80	74.5	75.4	81
060710005	CA	San Bernardino	110.3	112	100.3	101.8	109
060710012	CA	San Bernardino	95.0	98	87.3	90.1	90
060710306	CA	San Bernardino	84.0	86	76.8	78.6	83
060711004	CA	San Bernardino	105.7	109	97.2	100.2	106
060712002	CA	San Bernardino	97.7	99	90.1	91.3	102
060714001	CA	San Bernardino	90.3	91	82.6	83.3	87
060714003	CA	San Bernardino	104.0	107	95.2	98.0	114
060719002	CA	San Bernardino	87.3	89	80.1	81.6	86
060719004	CA	San Bernardino	108.7	111	99.5	101.6	110
060731006	CA	San Diego	83.0	84	76.9	77.9	79
060773005	CA	San Joaquin	77.3	79	71.3	72.8	70
060990005	CA	Stanislaus	81.0	82	75.4	76.3	79
060990006	CA	Stanislaus	83.7	84	77.5	77.8	80
061030004	CA	Tehama	79.7	81	72.3	73.4	74
061070006	CA	Tulare	84.7	86	79.1	80.3	83
061070009	CA	Tulare	89.0	89	82.6	82.6	88
061072002	CA	Tulare	82.7	85	75.5	77.6	83
061072010	CA	Tulare	84.0	86	77.0	78.8	80
061090005	CA	Tuolumne	80.7	83	75.6	77.8	77
080350004	CO	Douglas	77.3	78	71.7	72.3	81
080590006	CO	Jefferson	77.3	78	72.6	73.3	79
080590011	CO	Jefferson	79.3	80	73.8	74.4	80
080690011	CO	Larimer	75.7	77	71.3	72.6	75
090010017	CT	Fairfield	79.3	80	73.0	73.7	82
090013007	CT	Fairfield	82.0	83	74.2	75.1	80
090019003	CT	Fairfield	82.7	83	76.1	76.4	79
090099002	CT	New Haven	79.7	82	71.8	73.9	80
481671034	TX	Galveston	75.7	77	71.1	72.3	74
482010024	TX	Harris	79.3	81	75.2	76.8	79
482010055	TX	Harris	76.0	77	71.0	72.0	76
490110004	UT	Davis	75.7	78	72.9	75.1	77
490353006	UT	Salt Lake	76.3	78	73.6	75.3	74
490353013	UT	Salt Lake	76.5	77	74.4	74.9	73
550590019	WI	Kenosha	78.0	79	72.8	73.7	74
551010020	WI	Racine	76.0	78	71.3	73.2	73
551170006	WI	Sheboygan	80.0	81	73.6	74.5	75

* "N/A" is used to denote that there is no valid 2020 design value.

TABLE V.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
040278011	AZ	Yuma	72.3	74	70.5	72.2	68
060070007	CA	Butte	76.7	79	68.9	71.0	73
060090001	CA	Calaveras	77.0	78	70.9	71.9	72
060371103	CA	Los Angeles	73.0	74	70.5	71.5	76
060430006	CA	Mariposa	75.0	76	70.1	71.0	79

TABLE V.D–2—AVERAGE AND MAXIMUM 2016-CENTERED AND 2023 BASE CASE 8-HOUR OZONE DESIGN VALUES AND 2020 DESIGN VALUES (ppb) AT PROJECTED MAINTENANCE-ONLY RECEPTORS—Continued

Monitor ID	State	County	2016 centered average	2016 centered maximum	2023 average	2023 maximum	2020
060675003	CA	Sacramento	77.3	79	70.2	71.7	70
060711234	CA	San Bernardino	72.3	76	70.6	74.2	76
061112002	CA	Ventura	77.3	78	70.9	71.6	77
170310001	IL	Cook	73.0	77	69.6	73.4	75
170310032	IL	Cook	72.3	75	69.8	72.4	74
170310076	IL	Cook	72.0	75	69.3	72.1	69
170314201	IL	Cook	73.3	77	69.9	73.4	77
170317002	IL	Cook	74.0	77	70.1	73.0	75
320030075	NV	Clark	75.0	76	70.0	71.0	74
350130021	NM	Dona Ana	72.7	74	70.9	72.2	78
350130022	NM	Dona Ana	71.3	74	69.5	72.1	74
420170012	PA	Bucks	79.3	81	70.7	72.2	74
480391004	TX	Brazoria	74.7	77	70.1	72.3	73
481210034	TX	Denton	78.0	80	70.4	72.2	72
481410037	TX	El Paso	71.3	73	69.6	71.3	76
482011034	TX	Harris	73.7	75	70.3	71.6	73
482011035	TX	Harris	71.3	75	68.0	71.6	70
490450004	UT	Tooele	73.5	74	70.8	71.3	69
490570002	UT	Weber	73.0	75	70.6	72.5	N/A
490571003	UT	Weber	73.0	74	70.5	71.5	71
550590025	WI	Kenosha	73.7	77	69.2	72.3	74

In total, in the 2023 base case there are a total of 111 receptors nationwide including 85 nonattainment receptors and 26 maintenance-only receptors.[123] Of the 85 nonattainment receptors in 2023, 75 remain nonattainment receptors while 8 are projected to become maintenance-only receptors and 2 are projected to be in attainment in 2026. Of the 26 maintenance-only receptors in 2023, 13 are projected to remain maintenance-only receptors and 13 are projected to be in attainment in 2026. The projected average and maximum design values in 2026 for all receptors are included in the AQM TSD.

E. Pollutant Transport From Upwind States

1. Air Quality Modeling To Quantify Upwind State Contributions

This section documents the procedures the EPA used to quantify the impact of emissions from specific upwind states on ozone design values in 2023 and 2026 for the identified downwind nonattainment and maintenance receptors. The EPA used CAMx photochemical source apportionment modeling to quantify the impact of emissions in specific upwind states on downwind nonattainment and maintenance receptors for 8-hour ozone. CAMx employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations. The benefit of the photochemical model source apportionment technique is that all modeled ozone at a given receptor location in the modeling domain is tracked back to specific sources of emissions and boundary conditions to fully characterize culpable sources.

The EPA performed nationwide, state-level ozone source apportionment modeling using the CAMx Ozone Source Apportionment Technology/Anthropogenic Precursor Culpability Analysis (OSAT/APCA) technique[124] to quantify the contribution of 2023 and 2026 base case NO_X and VOC emissions from all sources in each state to the corresponding projected ozone design values in 2023 and 2026 at air quality monitoring sites. The CAMx OSAT/APCA model run was performed for the period May 1 through September 30 using the projected future base case emissions and 2016 meteorology for this time period. As described earlier, in the source apportionment modeling the Agency tracked (*i.e.,* tagged) the amount of ozone formed from anthropogenic emissions in each state individually as well as the contributions from other sources (*e.g.,* natural emissions).

In the state-by-state source apportionment model run, the EPA tracked the ozone formed from each of the following tags:

• States—anthropogenic NO_X and VOC emissions from each state tracked individually (emissions from all anthropogenic sectors in a given state were combined);

• Biogenics—biogenic NO_X and VOC emissions domain-wide (*i.e.,* not by state);

• Boundary Concentrations—concentrations transported into the air quality modeling domain;

• Tribes—the emissions from those tribal lands for which the Agency has point source inventory data in the 2016v1 emissions modeling platform (EPA did not model the contributions from individual tribes);

[123] The EPA's modeling also projects that three monitoring sites in the Uintah Basin (*i.e.,* monitor 490472003 in Uintah County, Utah and monitors 490130002 and 490137011 in Duchesne County, Utah) will have average design values above the NAAQS in 2023. However, as described in the AQM TSD, the Uinta Basin nonattainment area was designated as nonattainment for the 2015 ozone NAAQS not because of an ongoing problem with summertime ozone (as is usually the case in other parts of the country), but instead because it violates the ozone NAAQS in winter. The main causes of the Uinta Basin's wintertime ozone are sources located at low elevations within the Basin, the Basin's unique topography, and the influence of the wintertime meteorologic inversions that keep ozone and ozone precursors near the Basin floor and restrict air flow in the Basin. Because of the localized nature of the ozone problem at these sites the EPA has not identified these three monitors as receptors in Step 1 of this proposed rule.

[124] As part of this technique, ozone formed from reactions between biogenic VOC and NO_X with anthropogenic NO_X and VOC are assigned to the anthropogenic emissions.

• Canada and Mexico—anthropogenic emissions from sources in the portions of Canada and Mexico included in the modeling domain (the EPA did not model the contributions from Canada and Mexico separately);

• Fires—combined emissions from wild and prescribed fires domain-wide (*i.e.,* not by state); and

• Offshore—combined emissions from offshore marine vessels and offshore drilling platforms.

The contribution modeling provided contributions to ozone from anthropogenic NO_X and VOC emissions in each state, individually. The contributions to ozone from chemical reactions between biogenic NO_X and VOC emissions were modeled and assigned to the ''biogenic'' category. The contributions from wildfire and prescribed fire NO_X and VOC emissions were modeled and assigned to the ''fires'' category. That is, the contributions from the ''biogenic'' and ''fires'' categories are not assigned to individual states nor are they included in the state contributions.

For the Step 2 analysis, the EPA calculated a contribution metric that considers the average contribution on the 10 highest ozone concentration days (*i.e.,* top 10 days) in 2023. This average contribution metric is intended to provide a reasonable representation of the contribution from individual states to projected future year design values, based on modeled transport patterns and other meteorological conditions generally associated with modeled high ozone concentrations at the receptor. An average contribution metric constructed in this manner is beneficial since the magnitude of the contributions is directly related to the magnitude of the design value at each site.

The analytic steps for calculating the contribution metric for the 2023 analytic year are as follows:

(1) Calculate the 8-hour average contribution from each source tag to each monitoring site for the time period of the 8-hour daily maximum modeled concentrations in 2023;

(2) Average the contributions and average the concentrations for the top 10 modeled ozone concentration days in 2023;

(3) Divide the average contribution by the corresponding average concentration to obtain a Relative Contribution Factor (RCF) for each monitoring site;

(4) Multiply the 2023 average design values by the 2023 RCF at each site to produce the average contribution metric values in 2023.[125]

This same approach was applied to calculate contribution metric values at individual monitoring sites for 2026.[126]

The resulting contributions from each tag to each monitoring site in the U.S. for 2023 and 2026 can be found in the docket for this proposed rule. Additional details on the source apportionment modeling and the procedures for calculating contributions can be found in the AQM TSD.

The largest contribution from each state that is the subject of this rule to 8-hour ozone nonattainment and maintenance receptors in downwind states in 2023 and 2026 are provided in Table V.E.1–1 and Table V.E.1–2, respectively.

TABLE V.E.1–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023 (ppb)

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.88	0.71
Arizona	0.40	0.21
Arkansas	1.00	1.39
California	34.24	7.44
Colorado	0.07	0.20
Connecticut	0.01	0.21
Delaware	0.53	1.36
District of Columbia	0.04	0.07
Florida	0.16	0.15
Georgia	0.16	0.17
Idaho	0.55	0.57
Illinois	18.13	18.55
Indiana	6.60	7.10
Iowa	0.64	0.58
Kansas	0.42	0.59
Kentucky	0.83	0.88
Louisiana	5.39	7.03
Maine	0.01	0.01
Maryland	1.29	2.40
Massachusetts	0.30	0.30
Michigan	1.27	1.67
Minnesota	0.50	0.97
Mississippi	1.04	1.14
Missouri	1.08	1.66
Montana	0.08	0.11
Nebraska	0.26	0.36
Nevada	0.89	0.58
New Hampshire	0.10	0.06
New Jersey	8.85	5.79

[125] Note that a contribution metric value was not calculated for any receptor at which there were fewer than 5 days with model-predicted MDA8 ozone concentrations greater than or equal to 60 ppb in 2023. See the AQM TSD for information on those receptors that did not meet this criterion.

[126] In order to provide consistency in the contributions for 2023 and 2026, the contribution metric values for 2026 are based on the 2026 daily contributions for the same days that were used to calculate the contribution metric values for 2023.

TABLE V.E.1–1—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2023 (ppb)—Continued

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
New Mexico	0.30	0.13
New York	16.81	1.80
North Carolina	0.61	0.33
North Dakota	0.12	0.37
Ohio	1.94	1.88
Oklahoma	0.57	1.19
Oregon	1.10	1.31
Pennsylvania	6.90	0.51
Rhode Island	0.04	0.04
South Carolina	0.19	0.07
South Dakota	0.05	0.09
Tennessee	0.60	0.94
Texas	1.72	1.81
Utah	1.37	0.10
Vermont	0.02	0.02
Virginia	1.77	1.63
Washington	0.34	0.40
West Virginia	1.45	1.44
Wisconsin	0.19	2.61
Wyoming	0.81	0.19

TABLE V.E.1–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026 (ppb)

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Alabama	0.17	0.48
Arizona	0.35	0.23
Arkansas	0.62	1.30
California	33.45	4.85
Colorado	0.05	0.08
Connecticut	0.01	0.01
Delaware	0.42	0.52
District of Columbia	0.03	0.04
Florida	0.10	0.09
Georgia	0.14	0.16
Idaho	0.48	0.48
Illinois	17.81	18.14
Indiana	6.43	6.99
Iowa	0.57	0.57
Kansas	0.40	0.57
Kentucky	0.80	0.80
Louisiana	4.25	6.97
Maine	0.01	0.01
Maryland	1.11	1.23
Massachusetts	0.29	0.14
Michigan	1.03	1.58
Minnesota	0.36	0.91
Mississippi	0.36	0.90
Missouri	0.98	1.53
Montana	0.07	0.08
Nebraska	0.11	0.23
Nevada	0.81	0.51
New Hampshire	0.09	0.02
New Jersey	8.54	5.47
New Mexico	0.29	0.23
New York	16.58	11.29
North Carolina	0.38	0.54
North Dakota	0.11	0.34
Ohio	1.78	1.83
Oklahoma	0.54	0.72

TABLE V.E.1–2—LARGEST CONTRIBUTION TO DOWNWIND 8-HOUR OZONE NONATTAINMENT AND MAINTENANCE RECEPTORS IN 2026 (ppb)—Continued

Upwind state	Largest contribution to downwind nonattainment receptors	Largest contribution to downwind maintenance-only receptors
Oregon	0.98	0.88
Pennsylvania	6.82	4.74
Rhode Island	0.04	0.01
South Carolina	0.15	0.17
South Dakota	0.03	0.06
Tennessee	0.25	0.34
Texas	1.61	1.70
Utah	0.95	1.18
Vermont	0.02	0.01
Virginia	1.14	1.68
Washington	0.31	0.28
West Virginia	1.23	1.35
Wisconsin	0.15	2.44
Wyoming	0.46	0.80

2. Application of Contribution Screening Threshold

The EPA evaluated the magnitude of the contributions from each upwind state to downwind nonattainment and maintenance receptors. In Step 2 of the interstate transport framework, the EPA uses an air quality screening threshold to identify upwind states that contribute to downwind ozone concentrations in amounts sufficient to ''link'' them to these to downwind nonattainment and maintenance receptors. The contributions from each state to each downwind nonattainment or maintenance receptor that were used for the Step 2 evaluation can be found in the AQM TSD.

The EPA proposes to apply an air quality screening threshold of 1 percent of the NAAQS, as it has used since the CSAPR rulemaking, including in the CSAPR Update, the Revised CSAPR Update, and numerous actions evaluating states' transport SIP submittals. EPA continues to observe that the majority of nonattainment and maintenance receptors identified at Step 1 are impacted collectively by contributions of ozone transport from numerous upwind states. Therefore, application of a uniform screening threshold allows EPA to identify upwind states that share a responsibility under the interstate transport provision to eliminate their significant contribution.

The EPA recognizes that in 2018 it issued a memorandum indicating the potential for states to use a higher threshold at Step 2 in the development of their good neighbor SIP submissions where it could be technically justified. The August 2018 memorandum stated that ''it may be reasonable and appropriate'' for states to rely on an alternative 1 ppb threshold at Step 2.[127] (The memorandum also indicated that any higher alternative threshold, such as 2 ppb, would likely not be appropriate.) Here, the EPA proposes to fulfill its role under CAA section 110(c) in promulgating FIPs to directly implement good neighbor requirements, and in this role, the EPA notes that it is authorized to exercise discretion in making policy determinations such as the appropriateness of a particular contribution threshold that would otherwise have been exercised by states. Further, as the EPA has explained in several notices proposing transport SIP disapprovals, *see, e.g.,* 87 FR 9498 and 87 FR 9510 (Feb. 22, 2022), its experience since the issuance of the August 2018 memorandum regarding use of alternative thresholds leads the Agency to now believe it may not be appropriate to continue to attempt to recognize alternative contribution thresholds at Step 2, either in the context of SIPs or FIPs.

EPA's experience since 2018 is that allowing for alternative Step 2 thresholds may be impractical or otherwise inadvisable for a number of additional policy reasons. For a regional air pollutant such as ozone, consistency in requirements and expectations across all states is essential. In the context of a FIP proposal (as much as in the context of SIP actions), the Agency now believes using different thresholds at Step 2 with respect to the 2015 ozone NAAQS raises substantial policy consistency and practical implementation concerns.[128] The availability of different thresholds at Step 2 has the potential to result in inconsistent application of good neighbor obligations. From the perspective of ensuring effective regional implementation of good neighbor obligations, the more important analysis is the evaluation of the emissions reductions needed, if any, to address a state's significant contribution after consideration of a multifactor analysis at Step 3, including a detailed evaluation that considers air quality factors and cost. Where alternative thresholds for purposes of Step 2 may be ''similar'' in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of an alternative threshold would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This can create significant equity and consistency problems among states.

More importantly, in promulgating FIPs to address these obligations on a nationwide scale, national ozone transport policy is not well-served by allowing for less stringent thresholds at Step 2. The EPA recognized in the August 2018 memo that there was some similarity in the amount of total upwind contribution captured (on a nationwide basis) between 1 percent and 1 ppb. However, the EPA notes that while this

[127] August 2018 memo at 4.

[128] We note that Congress has placed on the EPA a general obligation to ensure the requirements of the CAA are implemented consistently across states and regions. *See* CAA section 301(a)(2). Where the management and regulation of interstate pollution levels spanning many states is at stake, consistency in application of CAA requirements is paramount.

may be true in some sense, that is hardly a compelling basis to move to a 1 ppb threshold. Indeed, the 1 ppb threshold has the disadvantage of losing a certain amount of total upwind contribution for further evaluation at Step 3 (*e.g.,* roughly 7 percent of total upwind state contribution was lost according to the modeling underlying the August 2018 memo;[129] in EPA's updated modeling, the amount lost is roughly 5 percent). Considering the core statutory objective of ensuring elimination of *all* significant contribution to nonattainment or interference of the NAAQS in other states and the broad, regional nature of the collective contribution problem with respect to ozone, there does not appear to be a compelling policy imperative in moving to a 1 ppb threshold.

Consistency with past interstate transport actions such as CSAPR, and the CSAPR Update and Revised CSAPR Update rulemakings (which used a Step 2 threshold of 1 percent of the NAAQS for two less stringent ozone NAAQS) is also important. Continuing to use a 1 percent of NAAQS approach ensures that as the NAAQS are revised and made more stringent, an appropriate increase in stringency at Step 2 occurs, so as to ensure an appropriately larger amount of total upwind-state contribution is captured for purposes of fully addressing interstate transport for the more stringent NAAQS. EPA made this point when it originally promulgated CSAPR to address the 1997 ozone NAAQS. The Agency continues to consider this an important consideration for the more stringent 2015 ozone NAAQS. *See* 76 FR 48237–38.

Lastly, the Agency does not find it to be a good use of limited resources to attempt to further justify the use of alternative thresholds for certain states at Step 2 for purposes of the 2015 ozone NAAQS. Therefore, while EPA articulated a potential basis for recognizing the usefulness of alternative Step 2 thresholds (particularly a 1 ppb threshold) in the August 2018 memorandum, EPA's experience and further evaluation since the issuance of that memo has revealed substantial programmatic and policy difficulties in attempting to implement this approach. Depending on comment and further evaluation of this issue, the EPA may determine to rescind the 2018 memorandum in the future.

In light of the considerations above, EPA proposes using a contribution threshold of 0.70 ppb as the quantification of 1 percent of the 2015 ozone NAAQS for purposes of Step 2.

a. States That Contribute Below the Screening Threshold

Based on EPA's modeling, the contributions from each of the following states to nonattainment or maintenance-only receptors in the 2023 analytic year are below the 1% of the NAAQS threshold: Arizona, Colorado, Connecticut, the District of Columbia, Florida, Georgia, Idaho, Iowa, Kansas, Maine, Massachusetts, Montana, Nebraska, New Hampshire, New Mexico, North Carolina, North Dakota, Rhode Island, South Carolina, South Dakota, Vermont, and Washington. The EPA has already approved many of these states' SIP submittals or is in the process of taking action to approve them. Because the contributions from these states to projected downwind air quality problems are below the screening threshold in the current modeling, these states are not within the scope of this proposed rule. Additionally, the EPA has made proposed or final determinations that two states outside the modeling domain for the air quality modeling analyzed in this proposed rulemaking—Hawaii[130] and Alaska[131]—do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state.

a. States That Contribute at or Above the Screening Threshold

Based on the maximum downwind contributions in Table V.E.1–1, the Step 2 analysis identifies that the following 22 states contribute at or above the 0.70 ppb threshold to downwind nonattainment receptors in 2023: Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oregon, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wyoming. Based on the maximum downwind contributions in Table V.E.1–1, the following 23 states contribute at or above the 0.70 ppb threshold to downwind maintenance-only receptors in 2023: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New York, Ohio, Oklahoma, Oregon, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. The levels of contribution between each of these linked upwind states and downwind nonattainment receptors and maintenance-only receptors are provided in the AQM TSD.

Among the linked states are several western states—California, Nevada, Oregon, Utah, and Wyoming. While the EPA has not previously included action on linked western states in its prior CSAPR rulemakings, the EPA has consistently applied the 4-step framework in evaluating good neighbor obligations from these states. On a case-by-case basis, the EPA has found in some instances with respect to the 2008 ozone NAAQS that a unique consideration has warranted approval of a linked western state's good neighbor SIP submittal without concluding that additional emissions reductions are required at Step 3 of the framework.[132] The EPA has also explained in prior actions that its air quality modeling is reliable for assessing downwind air quality problems and ozone transport contributions from upwind states throughout the nationwide modeling domain.[133]

In EPA's current analysis, the EPA finds that for one linked state—Oregon—the same considerations that led it to approve another state's SIP submission, Arizona's, for the 2008 ozone NAAQS apply to Oregon's circumstances for the 2015 ozone NAAQS. As explained in the following section, the EPA therefore proposes to affirm its prior approval of Oregon's good neighbor SIP submission for the 2015 ozone NAAQS. For the remaining western states included in this proposed rule, EPA's modeling supports a conclusion that these states are linked above the contribution threshold to identified ozone transport receptors in other states, and therefore, consistent with the treatment of all other states within the modeling domain, the EPA proposes to proceed to evaluate these states for a determination of ''significant contribution'' at Step 3.

In conclusion, as described above, states with contributions that equal or exceed 1 percent of the NAAQS to either nonattainment or maintenance receptors are identified as ''linked'' at Step 2 of the good neighbor framework and warrant further analysis for significant contribution to nonattainment or interference with

[129] *See* August 2018 memo, at 4.

[130] The EPA proposed to approve Hawaii's 2015 ozone transport SIP on September 28, 2021. *See* 86 FR 53571.

[131] The EPA approved Alaska's 2015 ozone transport SIP on December 18, 2019. *See* 84 FR 69331.

[132] *See* interstate transport approval actions under the 2008 ozone NAAQS for Arizona, California, and Wyoming at 81 FR 36179 (June 6, 2016), 83 FR 65093 (December 19, 2018), and 84 FR 14270 (April 10, 2019), respectively.

[133] *See* 81 FR 71991 (October 19, 2016), 82 FR 9155 (February 3, 2017).

maintenance under Step 3. The EPA proposes that the following 27 States are linked at Step 2 in 2023: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. In addition, the EPA proposes that the following 24 States are linked at Step 2 in 2026: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming. Three states, Alabama, Delaware, and Tennessee, that were linked in 2023 are not linked in 2026 because the receptor(s) to which each state was linked in 2023 are projected to attain by 2026.

F. Treatment of Certain Receptors in California and Implications for Oregon's Good Neighbor Obligations for the 2015 Ozone NAAQS

The EPA previously approved Oregon's September 25, 2018 transport SIP submittal for the 2015 ozone NAAQS on May 17, 2019 (84 FR 22376), because in an earlier round of modeling Oregon was not projected to contribute above 1 percent of the NAAQS to any downwind receptors. In EPA's updated modeling, Oregon is linked above the 1 percent of NAAQS threshold to several monitoring sites in California that would generally meet EPA's definition of nonattainment or maintenance ''receptors'' at Step 1.[134] However, EPA's analysis of the nature of the air quality problem at these monitoring sites leads EPA to propose a determination that these monitoring sites should not be treated as receptors for purposes of determining interstate transport obligations of upwind states under CAA section 110(a)(2)(D)(i)(I). EPA reaches this conclusion at Step 1 of its four-step framework.

The EPA previously made a similar assessment of the nature of certain other monitoring sites in California in approving Arizona's 2008 ozone NAAQS transport SIP submittal.[135] There, the EPA noted that a ''factor [. . .] relevant to determining the nature of a projected receptor's interstate transport problem is the magnitude of ozone attributable to transport from all upwind states collectively contributing to the air quality problem.'' [136] The EPA observed that only one upwind state (Arizona) was linked above 1 percent of the 2008 ozone NAAQS to the two relevant monitoring sites in California, and the cumulative ozone contribution from all upwind states to those sites was 2.5 percent and 4.4 percent of the total ozone, respectively. The EPA determined the size of those cumulative upwind contributions was ''negligible, particularly when compared to the relatively large contributions from upwind states in the East or in certain other areas of the West.'' [137] In that action, the EPA concluded the two California sites to which Arizona was linked should not be treated as receptors for the purposes of determining Good Neighbor obligations for the 2008 ozone NAAQS.[138]

The EPA proposes to make a similar finding for the monitoring sites in California otherwise projected in its current modeling to be ''receptors'' for the 2015 ozone NAAQS and to which Oregon is linked. The highest percent of the total cumulative upwind ozone contribution to any of these sites is 2.8 percent.[139] This is lower than the largest transport contribution relative to total ozone at the California sites identified in EPA's approval of Arizona's 2008 ozone transport SIP (4.4 percent).[140] Further, as was the case for the sites in California analyzed in EPA's Arizona action, the identified sites in California each have only one upwind state contributing above 1 percent of the NAAQS to them (Oregon). These monitoring sites in California are overwhelmingly impacted by in-state emissions to a degree not comparable with any other identified nonattainment or maintenance-only receptors in the country.

The EPA proposes to find that these monitoring sites should not be considered receptors for the purpose of assessing 2015 ozone NAAQS interstate transport obligations. The EPA is not proposing a different contribution threshold at Step 2 for Western states or receptors, nor does the EPA reach its conclusion based on any evaluation at Step 3 of emissions reduction opportunities in Oregon.

As a consequence of this proposed finding, the EPA continues to find that ozone-precursor emissions from Oregon do not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, because the total collective upwind state ozone contribution to the California monitoring sites is extremely low compared to the air quality problems typically addressed under the good neighbor provision. Therefore, the EPA is not proposing any change in this action to its prior approval of Oregon's SIP. The EPA is not proposing any new FIP requirements and is not proposing to require reductions from new or existing EGU or non-EGU sources in Oregon in this action. If, however, EPA were not to finalize this proposed approach, then EPA anticipates that it would apply the same control strategies in Oregon as applied in all other linked upwind states, as discussed in Sections VI and VII of this proposed rule. EPA requests public comment on its approach to characterizing the nature of the interstate transport problem at the California monitoring sites at issue and the consequent approach to assessing Oregon's good neighbor obligations.

VI. Quantifying Upwind-State NO_X Emissions Reduction Potential To Reduce Interstate Ozone Transport for the 2015 Ozone NAAQS

A. The Multi-Factor Test for Determining Significant Contribution

This section describes EPA's methodology at Step 3 of the 4-step framework for identifying upwind emissions that constitute ''significant'' contribution for the states subject to this proposed rule and focuses on the 26 states with FIP requirements identified in the sections above. Following the existing framework as applied in all of the prior CSAPR rulemakings, EPA's assessment of linked upwind state emissions is based primarily on analysis of several alternative levels of NO_X emissions control stringency applied uniformly across all of the linked states. The analysis includes assessment of non-EGU stationary sources in addition to EGU sources in the linked upwind states.

The EPA applies a multi-factor test—the same multi-factor test that was used in CSAPR, the CSAPR Update, and the Revised CSAPR Update [141]—to evaluate increasing levels of uniform NO_X control stringency. The multi-factor test, which is central to EPA's Step 3

[134] Monitors are listed in the AQM TSD included in the docket for this rulemaking. While EPA is providing information about cumulative upwind contribution to the California monitors, the Agency does not consider these monitors as ozone transport receptors in this proposal.

[135] 81 FR 15200 (March 22, 2016) (proposal); 81 FR 31513 (May 19, 2016) (final rule).

[136] 81 FR at 15203.

[137] *Id.*

[138] *Id.*

[139] See Air Quality Modeling TSDin the docket for this action.

[140] 81 FR at 15203; 81 FR 31513.

[141] *See* CSAPR, Final Rule, 76 FR 48208 (August 8, 2011).

quantification of significant contribution, considers cost, available emissions reductions, downwind air quality impacts, and other factors to determine the appropriate level of uniform NO_X control stringency that would eliminate significant contribution to downwind nonattainment or maintenance receptors. The selection of a uniform level of NO_X emissions control stringency across all of the linked states, reflected as a representative cost per ton of emissions reduction (or a weighted average cost per ton in the case of EPA's non-EGU and EGU analysis for 2026 mitigation measures), also serves to apportion the reduction responsibility among collectively contributing upwind states. This approach to quantifying upwind state emission-reduction obligations using uniform cost was reviewed by the Supreme Court in *EME Homer City Generation,* which held that using such an approach to apportion emissions reduction responsibilities among upwind states that are collectively responsible for downwind air quality impacts ''is an efficient and equitable solution to the allocation problem the Good Neighbor Provision requires the Agency to address.'' 572 U.S. at 519.

There are four stages in developing the multi-factor test: (1) Identify levels of uniform NO_X control stringency; (2) evaluate potential NO_X emissions reductions associated with each identified level of uniform control stringency; (3) assess air quality improvements at downwind receptors for each level of uniform control stringency; and (4) select a level of control stringency considering the identified cost, available NO_X emissions reductions, and downwind air quality impacts, while also ensuring that emissions reductions do not unnecessarily over-control relative to the contribution threshold or downwind air quality.

As mentioned in Section IV.A.2 of this proposed rule, commenters on previous ozone transport rules have suggested that the EPA should regulate VOCs as an ozone precursor. For this proposed rule, the EPA examined the results of the contribution modeling performed for this rule to identify the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state to each downwind receptor. Of the total upwind-downwind linkages in 2023, the contributions from NO_X emissions comprise 80 percent or more of the total anthropogenic contribution at the vast majority of linkages (136 out of 140 total). Across all receptors, the contribution from NO_X emissions ranges from 77 percent to 99 percent of the total anthropogenic contribution. This review of the portion of the ozone contribution attributable to anthropogenic NO_X emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NO_X-limited, rather than VOC-limited. Therefore, the EPA is proposing to determine that the regulation of VOCs as an ozone precursor is not necessary to eliminate significant contribution of ozone transport to downwind areas in this proposed rule. The remainder of this section focuses on EPA's strategy for reducing regional-scale transport of ozone by targeting NO_X emissions from stationary sources to achieve the most effective reductions of ozone transport over the geography of the affected downwind areas.

For both EGUs and non-EGUs, Section VI.B of this proposed rule describes the available NO_X emissions controls that the EPA evaluated for this proposed rule and their representative cost levels (in 2016$). Section VI.C of this proposed rule discusses EPA's application of that information to assess emissions reduction potential of the identified control stringencies. Finally, Section VI.D of this proposed rule describes EPA's assessment of associated air quality impacts and EPA's subsequent identification of appropriate control stringencies considering the key relevant factors (cost, available emissions reductions, and downwind air quality impacts).

This multi-factor approach is consistent with EPA's approach in prior transport actions, such as CSAPR. In addition, as was evaluated in the CSAPR Update and Revised CSAPR Update, the EPA evaluated possible over-control by examining whether an upwind state is linked solely to downwind air quality problems that could have been resolved at a lesser threshold of control stringency and whether an upwind state could reduce its emissions below the 1 percent air quality contribution threshold at a lesser threshold of control stringency. This analysis is described in Section VI.D of this proposed rule.

Finally, while the EPA has evaluated potential emissions reductions from non-EGU sources in prior rules, this is the first action for which the EPA is proposing non-EGU emissions reductions within the context of its 4-step interstate transport framework. The EPA applies its multi-factor test to non-EGUs and independently evaluates non-EGU industries in a consistent but parallel track to its Step 3 assessment for EGUs. This is consistent with the parallel assessment approach taken for EGUs and non-EGUs in the Revised CSAPR Update. Following the conclusions of the EGU and non-EGU multi-factor tests, the identified reductions for EGUs and non-EGUs are combined and collectively analyzed to assess their effects on downwind air quality and whether the rule achieves a full remedy to ''significant contribution'' while avoiding over-control.

In order to ensure that this rule implements a full remedy for the elimination of significant contribution from upwind states, the EPA has reviewed available information on all major industrial source sectors in the upwind states. This analysis leads the EPA to propose that both EGUs and certain large sources in several specific industrial categories should be evaluated for emissions control opportunities. As discussed in the sections that follow, the EPA proposes that for both EGUs and the selected non-EGU source categories, there are impactful emissions reduction opportunities available at reasonable cost-effectiveness thresholds. As in the Revised CSAPR Update, the EPA examines EGUs and non-EGUs in this section on consistent but distinct, parallel tracks due to differences stemming from the unique characteristics of the power sector compared to other industrial source categories. Since the NO_X SIP Call, EGUs have consistently been regulated under ozone transport rules. These units operate in a coordinated manner across a highly interconnected electrical grid. Their configuration and emissions control strategies are relatively homogenous, and their emissions levels and emissions control opportunities are generally very well understood due to longstanding monitoring and data-reporting requirements. Non-EGU sources, by contrast, are relatively heterogeneous, even within a single industrial category, and have far greater variation in existing emissions control requirements, emissions levels, and technologies to reduce emissions. In general, despite these differences, the information available for this proposal indicates that both EGUs and certain non-EGU categories have available cost-effective NO_X emissions reduction opportunities at relatively commensurate cost per ton levels, and these emissions reductions will make a meaningful improvement in air quality at the downwind receptors. Section VI.B.2 of this proposed rule describes EPA's process for selecting specific Tier I and Tier II non-EGU source categories included in this proposed rulemaking.

The EPA notes that its Step 3 analysis does not assess emissions reduction opportunities from mobile sources. The EPA continues to believe that title II of the CAA provides the primary authority and process for reducing ozone-precursor pollutants from mobile sources. EPA's federal mobile source programs have delivered and are projected to continue to deliver substantial nationwide reductions in both VOCs and NO_X emissions; these reductions are factored into the Agency's assessment of air quality and contributions at Steps 1 and 2. Further, states are generally preempted from regulating new vehicles and engines with certain exceptions, and therefore a question exists regarding EPA's authority to address such emissions when regulating in place of the states under CAA section 110(c). *See generally* CAA sections 209, 177. *See also* 86 FR 23099. As noted earlier, the EPA accounted for mobile source emissions reductions resulting from other federally enforceable regulatory programs in the development of emissions inventories used to support analysis for this proposed rulemaking, and the EPA does not evaluate any mobile source control measures in its Step 3 evaluation in this proposal.[142] For further discussion of EPA's existing and ongoing mobile source measures, *see* Section VI.B.4 of this proposed rule.

B. Identifying Control Stringency Levels

1. EGU NO_X Mitigation Strategies

In identifying levels of uniform control stringency for EGUs, the EPA assessed the same NO_X emissions controls that the Agency analyzed in the CSAPR Update and the Revised CSAPR Update, all of which are considered to be widely available in this sector: (1) Fully operating existing SCR, including both optimizing NO_X removal by existing operational SCRs and turning on and optimizing existing idled SCRs; (2) installing state-of-the-art NO_X combustion controls; (3) fully operating existing SNCRs, including both optimizing NO_X removal by existing operational SNCRs and turning on and optimizing existing idled SNCRs; (4) installing new SNCRs; (5) installing new SCRs; and (6) generation shifting (*i.e.,* emission reductions anticipated to occur from generation shifting from higher to lower emitting units at each of these stringency levels). For the reasons explained in the EGU NO_X Mitigation Strategies Proposed Rule TSD included in the docket for this proposed rule, the EPA determined that for the regional, multi-state scale of this rulemaking, only EGU NO_X emissions controls 1, 3, and 6 are possible for the 2023 ozone season (fully operating existing SCRs and SNCRs, and associated generation shifting). The EPA finds that it is not possible to install state-of-the-art NO_X combustion controls by the 2023 ozone season on a regional scale for Group 3 states not covered under the Revised CSAPR Rule. The EPA also determined that state-of-the-art NO_X combustion controls at EGUs are available by the beginning of the 2024 ozone season. All cost values discussed below for EGUs are in 2016 dollars.

a. Optimizing Existing SCRs

Optimizing (*i.e.,* turning on idled or improving operation of partially operating) existing SCRs can substantially reduce EGU NO_X emissions quickly, using investments that have already been made in pollution control technologies. With the promulgation of the CSAPR Update and the Revised CSAPR Update, most operators in the covered states improved their SCR performance and have continued to maintain that level of improved operation. However, this optimized SCR performance was not universal and not always sustained. Between 2017 and 2020, as the CSAPR Update ozone-season NO_X allowance price declined, NO_X emissions rates at some SCR-controlled EGUs increased. For example, power sector data from 2019 revealed that, in some cases, operating units had SCR controls that had been idled or were operating partially, and therefore suggested that there remained emissions reduction potential through optimization.[143] The EPA determined that optimizing all of these remaining SCRs in the 12 linked states for the Revised CSAPR Update was a readily available approach for EGUs to reduce NO_X emissions. This emissions reduction measure is currently available at EGUs across the broader geography affected in this proposed rulemaking (including in states not previously affected by the Revised CSAPR Update). The EPA thus proposes that SCR optimization, of both idled and partially operating controls, is a viable mitigation strategy for the 2023 ozone season.

The EPA estimates a representative marginal cost of optimizing SCR controls to be approximately $1,600 per ton, consistent with its estimation in the Revised CSAPR Update for this technology. EPA's EGU NO_X Mitigation Strategies Proposed Rule TSD for this rule describes a range of cost estimates for this technology noting that the costs are frequently lower than—and for the majority of EGUs, significantly lower than—this representative marginal cost. While the costs of optimizing existing, operational SCRs include only variable costs, the cost of optimizing SCR units that are currently idled considers both variable and fixed costs of returning the control into service. Variable and fixed costs include labor, maintenance and repair, parasitic load, and ammonia or urea for use as a NO_X reduction reagent in SCR systems. Depending on a unit's control operating status, the representative cost at the 90th percentile unit (among the relevant fleet of coal units with SCR covered in this rulemaking) ranges between $900 and $1,700 per ton. The EPA performed an in-depth cost assessment for all coal-fired units with SCRs and found that for the subset of SCRs that are already partially operating, the cost of optimizing is often much lower than $1,600 per ton and is often under $900 per ton. The EPA anticipates the vast majority of realized cost for compliance with this strategy to be better reflected by the $900 per ton end of that range (reflecting the 90th percentile of EGUs optimizing SCRs that are already partially operating) because this circumstance is considerably more common than EGUs that have ceased operating their SCR. EPA's analysis of this emissions control is informed by the latest engineering modeling equations used in EPA's IPM platform. These cost and performance equations were recently updated in the summer of 2021. The description and development of the equations are documented in EGU NO_X Mitigation Strategies Proposed Rule TSD and accompanying documents.[144] They are also

[142] The EPA recognizes that mechanisms exist under title I of the CAA that allow for the regulation of the use and operation of mobile sources to reduce ozone-precursor emissions. These include motor vehicle inspection and maintenance (I/M) programs, gasoline vapor recovery, clean-fuel vehicle programs, transportation control programs, and vehicle miles traveled programs. *See, e.g.,* CAA sections 182(b)(3), 182(b)(4), 182(c)(3), 182(c)(4), 182(c)(5), 182(d)(1), 182(e)(3), and 182(e)(4). The EPA views these programs as most effective and appropriate in the context of the planning requirements applicable to designated nonattainment areas.

[143] *See* ''Ozone Season Data 2018 vs. 2019'' and ''Coal-fired Characteristics and Controls'' at *https://www.epa.gov/airmarkets/power-plant-data-highlights#OzoneSeason.*

[144] The CSAPR Update estimated $1,400 per ton as a representative cost of turning on idled SCR controls. EPA used the same costing methodology

Continued

implemented in an interactive spreadsheet tool called the Retrofit Cost Analyzer and applied to all units in the fleet. These materials are available in the docket for this proposal.

The EPA is using the same methodology to identify SCR performance as it did in the Revised CSAPR Update. To estimate EGU NO_X reduction potential from optimizing, the EPA considers the difference between the non-optimized NO_X emissions rates and an achievable operating and optimized SCR NO_X emissions rate. To determine this rate, EPA evaluated nationwide coal-fired EGU NO_X ozone season emissions data from 2009 through 2019 and calculated an average NO_X ozone season emissions rate across the fleet of coal-fired EGUs with SCR for each of these eleven years. The EPA found it prudent to not consider the lowest or second-lowest ozone season NO_X emissions rates, which may reflect SCR systems that have all new components (*e.g.,* new layers of catalyst). Data from these systems are potentially not representative of ongoing achievable NO_X emissions rates considering broken-in components and routine maintenance schedules. To identify the potential reductions from SCR optimization in this proposed rule, the EPA followed the same methodology as the Revised CSAPR Update. Considering the emissions data over the full time period from 2009–2019 data results in a third-best rate of 0.079 pounds NO_X per million British thermal units (lb/mmBtu).[145] Therefore, consistent with the Revised CSAPR Update, where EPA identified 0.08 lb/mmBtu as a reasonable level of performance for units with optimized SCR, the EPA proposes a rate of 0.08 lb/mmBtu as the optimized rate for this rule. The EPA notes that half of the SCR-controlled EGUs achieved a NO_X emissions rate of 0.064 lbs/mmBtu or less over their third-best entire ozone season. Moreover, for the SCR-controlled coal units that the EPA identified as having a 2021 emissions rate greater than 0.08 lb/mmBtu, the EPA verified that in prior years, the majority (more than 90 percent) of these same units had demonstrated and achieved a NO_X emissions rate of 0.08 lb/mmBtu or less on a seasonal or monthly basis. This further supports EPA's determination that 0.08 lb/mmBtu reflects a reasonable emissions rate for representing SCR optimization at coal steam units in identifying uniform control stringency. This emissions rate assumption of 0.08 lb/mmBtu reflects what those units would achieve on average when optimized, recognizing that individual units may achieve lower or higher rates based on unit-specific configuration and dispatch patterns. Units historically performing at, or better, than this rate of 0.08 lb/mmBtu are assumed to continue to operate at that prior performance level.

Given the magnitude and duration of the air quality problems addressed by this rulemaking, the EPA also applied the same methodology to identify a reasonable level of performance for optimizing existing SCRs at oil- and gas-fired steam units and simple cycle units (for which EPA determined that a 0.03 lb/mmBtu emissions rate reflected SCR optimization) as well as at combined-cycle units (for which the EPA determined that a 0.012 lb/mmBtu emissions rate reflected SCR optimization).

The EPA evaluated the feasibility of optimizing idled SCRs for the 2023 ozone season. Based on industry past practice, the EPA determined that idled controls can be restored to operation quickly (*i.e.,* in less than 2 months). This timeframe is informed by many electric utilities' previous long-standing practice of utilizing SCRs to reduce EGU NO_X emissions during the ozone season while putting the systems into protective lay-up during the non-ozone season months. For example, this was the long-standing practice of many EGUs that used SCR systems for compliance with the NO_X Budget Trading Program. It was quite typical for SCRs to be turned off following the September 30 end of the ozone season control period. These controls would then be put into protective lay-up for several months of non-use before being returned to operation by May 1 of the following ozone season.[146] Therefore, the EPA believes that optimization of existing SCRs is possible for the portion of the 2023 ozone season covered under this proposed rule.

The vast majority of SCR-controlled units (nationwide and in the 25 linked states for which EPA is issuing a FIP for EGUs) are already partially operating these controls during the ozone season based on reported 2021 emissions rates. Existing SCRs operating at partial capacity still provide functioning, maintained systems that may only require an increased chemical reagent feed rate (*i.e.,* ammonia or urea) up to their design potential and catalyst maintenance for mitigating NO_X emissions; such units may require increased frequency or quantity of deliveries, which can be accomplished within a few weeks. In many cases, EGUs with SCR have historically achieved more efficient NO_X removal rates than their current performance and can therefore simply revert to earlier operation and maintenance plans that achieved demonstrably better SCR performance.

In the 12 states subject to this control stringency in the Revised CSAPR Update, the EPA observed significant immediate-term improvements in SCR performance in the first ozone season following finalization of that rule, as evidenced in particular by the sharp drop in emissions rate at Miami Fort unit 7 (*see* EGU NO_X Mitigation Strategies Proposed Rule TSD). Such empirical data further illustrates the viability of this mitigation strategy for the 2023 control period in response to this rule.

b. Installing State-of-the-Art NO_X Combustion Controls

The EPA estimates that the representative cost of installing state-of-the-art combustion controls is comparable to, if not notably less than, the estimated cost of optimizing existing SCR (represented by $1,600 per ton). State-of-the-art combustion controls such as low-NO_X burners (LNB) and over-fire air (OFA) can be installed or updated quickly and can substantially reduce EGU NO_X emissions. Nationwide, approximately 99 percent of coal-fired EGU capacity greater than 25 MW is equipped with some form of combustion control; however, the control configuration or corresponding emissions rates at a small portion of those units (including units in those states covered in this action) indicate they do not currently have state-of-the-

while updating for input cost increases (*e.g.,* urea reagent) to arrive at $1,600 per ton in the final Revised CSAPR Update (while also updating from 2011 dollars to 2016 dollars).

[145] The EPA notes that updating the inventory of units to reflect recent retirements and most recent year data (*e.g.,* 2009–2021) would provide a lower value of 0.071 lb/mmBtu. This value is lower than the 0.08 pounds per million British thermal units (lb/mmBtu) assessed in the Revised CSAPR Update as it reflects 2020 data and also excludes the SCR performance of since retired coal units with SCRs. However, 2020 was an outlier year (related to pandemic impacts on the electric grid). Additionally, a unit's retirement does not obviate the usefulness of its data for assessing technology performance. Consequently, EPA is proposing the same value of 0.08 lb/mmBtu identified at the time of the final Revised CSAPR Update Rule.

[146] In the 22-state CSAPR Update region, 2005 EGU NO_X emissions data suggest that 125 EGUs operated SCR systems in the summer ozone season while idling these controls for the remaining 7 non-ozone season months of the year. Units with SCR were identified as those with 2005 ozone season average NO_X rates that were less than 0.12 lbs/mmBtu and 2005 average non-ozone season NO_X emissions rates that exceeded 0.12 lbs/mmBtu and where the average non-ozone season NO_X rate was more than double the ozone season rate.

art combustion control technology. As described in the Revised CSAPR Update, the Agency updated its NO_X emissions rates for upgrading existing combustion controls to state-of-the-art combustion control. The EPA is maintaining its determination that NO_X emissions rates of 0.146 to 0.199 lbs/mmBtu can be achieved on average depending on the unit's boiler configuration,[147] and, once installed, reduce NO_X emissions at all times of EGU operation.

These assumptions are consistent with the Revised CSAPR Update and they are further discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD. In particular, the EPA proposes to apply the 0.199 lb/mmBtu emissions rate assumption for all unit types, consistent with its determination in the Revised CSAPR Update. The average emissions rate assumption derived from EPA's analysis would be 0.199 lb/mmBtu for combustion controls on dry bottom wall fired units and 0.146 lb/mmBtu for tangentially fired units. However, stakeholders have provided detailed analysis of how other unit considerations, such as coal rank, can result in large deviations from what has been historically demonstrated with this combustion control technology. Based on this and EPA's review of historical performance data for tangentially-fired units by coal rank with state-of-the-art combustion controls, the EPA determined in the final Revised CSAPR Update that it was appropriate to use the 0.199 lb/mmBtu rate for both tangentially and wall-fired units when estimating reduction potential for units with combustion control upgrade potential.

The EPA proposes to continue that approach in this action. Many of the likely impacted units burn bituminous coal, and the 0.146 lb/mmBtu nationwide average for tangentially-fired (inclusive of subbituminous units) appears to be below the demonstrated emissions rate of state-of-the-art combustion controls for bituminous coal units of this boiler type. Therefore, EPA's assumption of 0.199 lb/mmBtu for combustion controls is robust to current and future coal choice at a unit.

In promulgating CSAPR, the EPA examined the feasibility of installing combustion controls, and found that industry had demonstrated ability to install state-of-the-art LNB controls on a large unit (800 MW) in under six months when including the pre-installation phases (design, order placement, fabrication, and delivery).[148] In prior rules, the EPA has documented its own assessment of combustion control timing installation as well as evaluated comments it received regarding installation of combustion controls from the Institute of Clean Air Companies.[149] Those comments provided information on the equipment and typical installation time frame for new combustion controls, accounting for all steps. Commenters noted that it generally takes between 6–8 months on a typical boiler—covering the time through bid evaluation through start-up of the technology. The deployment schedule is repeated here as:

- 4–8 weeks—bid evaluation and negotiation
- 4–6 weeks—engineering and completion of engineering drawings
- 2 weeks—drawing review and approval from user
- 10–12 weeks—fabrication of equipment and shipping to end user site
- 2–3 weeks—installation at end user site
- 1 week—commissioning and start-up of technology

Given the above timeframe of approximately 6 to 8 months to complete combustion control installation in the region, the EPA is proposing to determine that installation of state-of-the-art combustion controls is a readily available approach for EGUs to reduce NO_X emissions by the start of the 2024 ozone season. More details on these analyses can be found in the EGU NO_X Mitigation Strategies Proposed Rule TSD.

The cost of installing state-of-the-art combustion controls per ton of NO_X reduced is dependent on the combustion control type and unit type. The EPA estimates the cost per ton of state-of-the-art combustion controls to be $400 per ton to $1,200 per ton of NO_X removed using a representative capacity factor of 85 percent. This cost fits well within EPA's representative cost threshold observed for SCR optimization and combustion controls (of $1,600 per ton) which would accommodate combustion control upgrade even under scenarios where a lower capacity factor is assumed. *See* the EGU NO_X Mitigation Strategies Proposed Rule TSD for additional details.

c. Optimizing Already Operating SNCRs or Turning on Idled Existing SNCRs

Optimizing already operating SNCRs or turning on idled existing SNCRs can also reduce EGU NO_X emissions quickly, using investments in pollution control technologies that have already been made. Compared to no post-combustion controls on a unit, SNCRs can achieve a 25 percent reduction on average in EGU NO_X emissions (with sufficient reagent). They are less capital intensive but less efficient at NO_X removal than SCRs. These controls are in use to some degree across the U.S. power sector. In the 25 linked states identified in this proposed rule with identified EGU reductions in their proposed FIP, approximately 11 percent of coal-fired EGU capacity is equipped with SNCR.[150] Recent power sector data suggest that, in some cases, SNCR controls have been operating less in 2021 relative to performance in prior years.

The EPA determined that optimizing already operating SNCRs or turning on idled SNCRs is an available approach for EGUs to reduce NO_X emissions, has similar implementation timing to restarting idled SCR controls (less than 2 months for a given unit), and therefore could be implemented in time for the 2023 ozone season. The EPA is proposing implementation of this emissions control technology beginning in the 2023 ozone season.

Using an updated data assessment using the Retrofit Cost Analyzer described in the EGU NO_X Mitigation Strategies Proposed TSD, the EPA estimates a representative cost of optimizing SNCR ranging from approximately $1,800 per ton (for partially operating SNCRs) to $3,900 per ton (for idled SNCRs). For existing SNCRs that have been idled, unit operators may need to restart payment of some fixed and variable operating costs including labor, maintenance and repair, parasitic load, and ammonia or urea. The EPA determined that the majority of units with existing SNCR optimization potential were already partially operating their controls. Therefore, the EPA proposes a representative cost of $1,800 per ton for SNCR optimization as this value best reflects the circumstances of the majority of the affected EGUs with SNCR.

[147] Details of EPA's assessment of state-of-the-art NO_X combustion controls are provided in the EGU NO_X Mitigation Strategies Proposed Rule TSD.

[148] The EPA finds that, generally, the installation phase of state-of-the-art combustion control upgrades—on a single-unit basis—can be as little as 4 weeks to install with a scheduled outage (not including the pre-installation phases such as permitting, design, order, fabrication, and delivery) and as little as 6 months considering all implementation phases.

[149] EPA–HQ–OAR–2015–0500–0093.

[150] *https://www.epa.gov/airmarkets/national-electric-energy-data-system-needs-v6.*

d. Installing New SNCRs

Like existing SNCRs, new SNCR retrofit is also available to power plants and can achieve a 25% NO_X reduction on average. The EPA evaluated potential emissions reductions and associated costs from retrofitting EGUs with new SNCR post-combustion controls at steam units lacking such controls. New SNCR technology provides owners with a relatively less capital-intensive option for reducing NO_X emissions compared to new SCR technology, albeit at the expense of higher operating costs on a per-ton basis and less total emissions reduction potential. SNCR is more widely observed on relatively smaller coal units given its low capital/variable cost ratio. The average capacity of a coal unit with SNCR is half the size of the average capacity of coal unit with SCR.[151] Given these observations, the EPA identifies this technology as an emissions reduction measure for coal units less than 100 MW lacking post-combustion NO_X control technology. As described in the EGU NO_X Mitigation Strategies Proposed Rule TSD, the EPA estimated that $6,700 per ton reflects a representative SNCR retrofit cost level for a majority of these units.

SNCR installations generally have shorter project installation timeframes relative to other post-combustion controls. The time for engineering review, contract award, fabrication, delivery, and hookup is as little as 16 months including pre-contract award steps for an individual power plant installing controls on more than one boiler. This timeframe would mean the control would be available for the start of the 2024 or 2025 ozone season (*i.e.,* calculating 16 months from when this proposal is finalized). However, SNCR retrofits have less pollution reduction potential than alternative post-combustion controls such as SCRs. The EPA is not identifying SNCR technology as a strategy for larger steam units due to this lower removal efficiency and the empirical evidence of existing sources preferring the more efficient SCRs. Even for those smaller units less than 100 MWs identified as potential candidates for this technology, the EPA does not want to preclude those units from pursuing more advanced pollution controls. Therefore, the EPA also considers the point in time when all types of post-combustion control installation could be achieved—*i.e.,* by the 2026 ozone season. SNCR installation share similar implementation steps with and also need to account for the same regional factors as SCR installations.[152] Therefore, while the EPA is determining that at least 16 months would be needed to complete all necessary steps of SNCR development and installation at the EGUs not currently equipped with SNCRs in the 25 states linked to downwind receptors in this proposed rule, the EPA notes that the Agency evaluated SNCR as a post-combustion control technology collectively with SCR and estimated installation timing considerations of 36 months. EPA believes its proposed collective timing considerations for post-combustion control retrofit (SNCR and SCR) are practicable given that the preferable capital-intensive investment retrofit decision would be highly unit-specific and subject to a unit's compliance strategy choices with respect to multiple regulatory requirements.

Nonetheless, the EPA is requesting comment on whether post-combustion control timing assumptions (SCR and SNCR) should be decoupled, which would result in the EPA using the 16-month time frame specific to SNCR installation to estimate the first year in which these reductions are available. The EPA is only identifying this technology for units less than 100 MW (a size at which units rarely implement SCR retrofit technology). In effect, decoupling these timing assumptions would move the reductions associated with this control stringency from beginning in the 2026 ozone season to beginning in the 2024 or 2025 ozone season (depending on when this proposal is finalized). This would impact approximately 1,000 tons of identified reduction potential related to SNCR retrofit.

e. Installing New SCRs

Selective Catalytic Reduction (SCR) controls already exist on approximately 60% of the coal fleet in the linked states that would be subject to a FIP in this proposed rulemaking. Nearly every pulverized coal unit larger than 100 MW built in the last 30 years has installed this control, which is generally required for Best Available Control Technology (BACT) purposes. Other than circulating fluidized bed coal units which can achieve a comparably low emissions rate without this technology, the EPA identifies this emissions reduction measure for coal steam units greater than or equal to 100 MW. SCR is widely available for existing coal units of this size and can provide significant emissions reduction potential, with removal efficiencies of up to 90 percent. The EPA limited its consideration of SCR technology to steam units greater than or equal to 100 MW. The costs for retrofitting a plant smaller than 100 MW with SCR increase rapidly due to a lack of economy of scale.[153]

The amount of time needed to retrofit an EGU with new SCR extends beyond the 2023 ozone season. The EPA proposes that a strategy of retrofitting new SCR on a fleetwide, regional scale is available by, but no earlier than, the 2026 ozone season. Similar to the SNCR retrofits discussed above, the EPA evaluated potential emissions reductions and associated costs from this control technology, as well as the impacts and need for this emissions control strategy, at the earliest point in time when their installation could be achieved. In the past, the EPA has found the amount of time to retrofit a single EGU with new SCR, depending on the regulatory program under which such control may be required, may vary between approximately 2 and 4 years depending on site-specific engineering considerations and on the number of installations being considered. This includes steps for engineering review, construction permit, operating permit, and control technology installation (including fabrication, pre hookup, control hookup, and testing). EPA's assessment of installation procedures suggests as little as 21 months may be needed for a single SCR at an individual plant and 36 months at a single plant with multiple boilers. EPA's assessment of units with SCR retrofit potential indicate the majority fall into this first classification, *i.e.,* a single SCR at a power plant. Given that some of the assumed SCR retrofit potential occurs at plants with multiple units identified with retrofit potential, and given the total volume of SCR retrofit capacity being implemented across the region, The EPA is proposing 36 months as an appropriate time frame to accommodate both instances as well as scheduling necessities attributable to the regional-scale nature of the program.

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[151] *See* EGU NO_X Mitigation Strategies Proposed Rule TSD for additional discussion.

[152] A month-by-month evaluation of SNCR installation is discussed in EPA's NO_X Mitigation Strategies Proposed Rule TSD and in EPA's "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies". The analysis in this exhibit estimates the installation period from contract award as within a 10–13-month timeframe. The exhibit also indicates a 16-month timeframe from start to finish, inclusive of pre-contract award steps of the engineering assessment of technologies and bid request development. The timeframe cited for installation of SNCR at an individual source in this action is consistent with this more complete timeframe estimated by the analysis in the exhibit.

[153] IPM Model-Updates to Cost and Performance for APC Technologies. SCR Cost Development Methodology for Coal-fired Boilers. February 2022.

Further, the EPA notes that it has previously determined in the context of ozone transport that regional scale implementation of SCRs at numerous EGUs is achievable in 36 months. *See* 63 FR 57356, 57447–50 (October. 27, 1998). The EPA has at times also found up to 39–48 months to be an appropriate installation timeframe for regionwide actions when the EPA is evaluating multiple installations at multiple locations.[154] However, as discussed in greater detail in Section VII.A in this proposed rule, the EPA now recognizes that the *Wisconsin* decision invalidated the standard under which the EPA had been evaluating appropriate compliance timeframes for purposes of assessing interstate transport under the good neighbor provision when the Agency had concluded a 39–48 month timeframe to install SCR was appropriate.

The Agency examined the cost for retrofitting a coal unit with new SCR technology, which typically attains controlled NO_X rates of 0.05 lbs/mmBtu or less. These updates are further discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD.[155] Based on the characteristics of coal units of 100 MW or greater capacity that do not have post-combustion NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $11,000 per ton.[156]

The 0.05 lb/mmBtu emission rate performance assumption for new SCR retrofits is supported by historical data and third party independent review by pollution control engineering and consulting firms. The EPA first examined unit-level emission rate data for coal-fired units that had a relatively recent SCR installation (within the last 10 years). These SCR retrofits reflect the most recent vintage of the pollution control technology applied to the power sector and are representative of new SCR retrofit capability. Although regulatory requirements or economic incentives were not necessarily in place during this time period for these SCRs to operate at their full potential, the EPA found that half of these units had still demonstrated a seasonal emission rate of 0.05 lb/mmBtu or lower and 78 percent had demonstrated this rate on a monthly basis. The best performing 10 percent of these SCRs were demonstrating seasonal emission rates of 0.036 lb/mmBtu during this time.

While the EPA identified the 0.05 lb/mmBtu performance assumption consistent with historical data, these performance levels are also informed and consistent with the Agency's IPM modeling assumptions used for more than a decade. These modeling assumptions are based on input from leading engineering and pollution control consulting entities. Most recently, these data assumptions were affirmed and updated in the summer of 2021 and included in the docket for this rulemaking. The EPA relies on a global firm providing engineering, construction management, and consulting services for power and energy with expertise in grid modernization, renewable energy, energy storage, nuclear power, and fossil fuels. Their familiarity with state-of-the art pollution controls at power plants derives from experience providing comprehensive project services—from consulting, design, and implementation to construction management, commissioning, and operations/maintenance. This review and update supported the 0.05 lb/mmBtu performance assumption as a representative emission rate for new SCR across coal types.

The EPA performed an assessment for oil/gas steam units in which it evaluated the nationwide performance of those units with SCR technology. For these units, the EPA tabulated EGU NO_X ozone season emissions data from 2009 through 2021 and calculated an average NO_X ozone season emissions rate across the fleet of oil- and gas-fired EGUs with SCR for each of these years. The EPA identified the third lowest year which yielded an SCR performance rate of 0.03 lb/mmBtu as representative of performance for this retrofit technology applied to this type of EGU. Next, the EPA evaluated the emissions and operational characteristics for the existing oil/gas steam fleet lacking SCR technology. EPA's analysis indicated that the majority of reduction potential (approximately 76 percent) from these units occurred at units greater than or equal to 100 MW and that were emitting more than 150 tons per ozone season (*i.e.,* approximately 1 ton per day). Moreover, the cost of reductions for units falling below these criteria increased significantly. Therefore, the EPA identified the portion of the oil/gas steam fleet meeting this criteria as representative of the SCR retrofit reduction potential.[157] For this segment of the oil/gas steam units lacking post-combustion NO_X control technology, the EPA estimated a weighted-average representative SCR cost of $7,700 per ton.

f. Generation Shifting

Finally, EPA evaluates emissions reduction potential from generation shifting across the representative dollar per ton levels estimated for the emissions controls considered above. As the cost of emitting NO_X increases, it becomes increasingly cost-effective for units with lower NO_X rates to increase generation, while units with higher NO_X rates reduce generation. Because the cost of generation is unit-specific, this generation shifting occurs incrementally on a continuum. Consequently, there is more generation shifting at higher cost NO_X-control levels.

It is reasonable for the EPA to quantify and include the emissions reduction potential from generation shifting at cost levels that are representative of the emissions control technologies evaluated in the multi-factor analysis, because all EGUs that would be regulated by this proposed rule participate in highly coordinated, interconnected systems where generation shifting will inevitably occur in response to pollution control requirements. If the EPA did not account for such emissions reduction potential in its analysis at Step 3, seeking emissions reductions from pollution control measures at higher-NO_X-emitting EGUs would still incentivize generation shifting toward lower-NO_X-emitting EGUs when sources comply under the remedy mechanism established in Step 4, and the corresponding reductions in emissions achieved through such generation shifting would potentially substitute for some of the emissions reductions intended through control operation and installation, potentially lessening the implementation of those mitigation strategies. Generation shifting treatment and results are discussed in greater detail in the EGU NO_X Mitigation Strategies Proposed TSD and the Ozone Transport Policy Analysis Proposed Rule TSD.

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[154] *See, e.g.,* CSAPR Close-Out, 83 FR 65878, 65895 (December 21, 2018). *See also* Final Report: Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, EPA–600/R–02/073 (Oct. 2002), available at *https://nepis.epa.gov/Adobe/PDF/P1001G0O.pdf.*

[155] As noted in that TSD, approximately half of the recent SCR retrofits (*i.e.,* installed in the last 10 years) have demonstrated an emission rate across the ozone season below 0.05 lb/mmBtu, even absent a requirement or strong incentive to operate at that level in many cases.

[156] This cost estimate is representative of coal units lacking any post-combustion control. A subset of units within the universe of coal sources with SCR retrofit potential, but that have an existing SNCR technology in place would have a weighted average cost that falls above this level, but still cost effective. See the EGU NO_X Mitigation Strategies Proposed Rule TSD for more discussion.

[157] The EPA used a 3 year average of 2019–2021 reported ozone season emissions to derive a tons per ozone season value representative for each covered oil/gas steam unit.

The EPA notes that its treatment of generation shifting here is consistent with the prior CSAPR rulemakings and is grounded on the same statutory authority. *See, e.g.,* 76 FR 48208, 48280 (August 8, 2011). As the EPA explained in the CSAPR Update:[158]

> The good neighbor provision requires state and federal plans implementing its requirements to ''prohibit[ ] . . . *any source or other type of emissions activity within the State* from emitting any air pollutant in *amounts* which will'' significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any other state. CAA section 110(a)(2)(D)(i)(I) (emphasis added). . . . [T]he statute does not limit the EPA's authority under the good neighbor provision to basing regulation only to control strategies for individual sources. The statute authorizes the state or EPA in promulgating a plan to prohibit emissions from ''any source or other type of emissions activity within the State'' that contributes (as determined by EPA) to the interstate transport problem with respect to a particular NAAQS. This broad statutory language shows that Congress was directing the states and the EPA to address a wide range of entities and activities that may be responsible for downwind emissions. However, this provision is silent as to the type of emissions reduction measures that the states and the EPA may consider in establishing emissions reduction requirements, and it does not limit those measures to individual source controls. . . . The EPA reasonably interprets this provision to authorize consideration of a wide range of measures to reduce emissions from sources, which is consistent with the broad scope of this provision, as noted immediately above.

81 FR 74545.[159] The EPA continued to apply this same understanding in the Revised CSAPR Update. *See* 86 FR 23054, 23095–97 (April 30, 2021); *see also* 85 FR 68964, 68992–93 (October 30, 2020).

The EPA requests comment on the suite of mitigation technologies for EGUs described earlier and assessed in the determination of significant contribution. The EPA requests comment on the assumed performance or emissions rate of the technology, the representative cost, and the timing for installation.[160] Additionally, the EPA requests comment on whether other EGU ozone-season NO_X Mitigation technologies should be required to eliminate significant contribution. For instance, the EGU NO_X Mitigation Strategies Proposed Rule TSD discusses certain mitigation technologies that have been applied to ''peaking'' units (small, low capacity factor gas combustion turbines often only operating during periods of peak demand). To the extent that any of these sources meet the applicability requirements and are covered in the Group 3 trading program under this proposed rulemaking, they would have an incentive to reduce emissions consistent with the ozone season NO_X allowance price. The EPA has not identified determinative evidence that there are additional meaningful, cost-effective upwind reductions from these emission controls that are not already being addressed by state rules. EPA's analysis discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD highlights that there are 32 units emitting more than 10 tons per year on average for the 2019–2021 ozone seasons and lacking combustion controls or more advanced controls (totaling approximately 1,000 tons of ozone season NO_X emissions in 2021). Some of the units in the limited inventory are subject to state requirements delivering additional reductions by 2023. Moreover, the EPA analysis suggested $25,000–$30,000 per ton estimates for dry low NO_X burners or ultra-low NO_X burners at these units, and over $100,000 per ton for SCR retrofit at some combustion turbines. Therefore, the EPA is not proposing any additional reductions from new controls for inclusion in its combustion control or retrofit technology breakpoints. Although the EPA is not proposing a mitigation technology for this type of unit, it requests comment on the potential emissions reductions and cost from such sources in covered states that do not currently have mitigation requirements for such sources.

2. Non-EGU NO_X Mitigation Strategies

a. Determining Non-EGU NO_X Reduction Potential

The number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the universe of non-EGU sources, makes it challenging to define a single method to identify appropriate control technologies, measures, or strategies and resulting impactful emissions reductions. Because of these challenges, the EPA adopted a different approach for assessing non-EGU NO_X emissions reduction potential than the approach for EGUs described in the preceding section. To assess emissions reduction potential from non-EGUs, the EPA first performed a screening assessment to identify those industries that could have the greatest air quality impact at downwind receptors. This was followed by an assessment estimating annual NO_X emissions reduction potential at specific cost thresholds for each of the most impactful industries. Next, the EPA estimated the reductions in ozone concentrations resulting from the emissions reductions for each industry in each of the 27 linked upwind states. As described later, the results indicate that the most impactful industries fall into two tiers based on the estimated reductions in ozone concentrations associated with the NO_X emissions reductions.

The Agency incorporated air quality information as a first step in an analytical framework to help determine potentially impactful industries to focus on for further assessing potential controls, emissions reduction potential, air quality improvements, and costs. The EPA developed the analytical framework using inputs from the air quality modeling for the Revised CSAPR Update for 2023,[161] as well as the projected 2023 annual emissions inventory from the 2016v2 emissions platform that was used for the air quality modeling for this proposed rule. Additional information on the analytical framework is presented in the Non-EGU Screening Assessment memorandum available in the docket.

Using the Revised CSAPR Update modeling for 2023, the EPA identified upwind states linked to downwind nonattainment or maintenance receptors using the 1 percent of the NAAQS threshold criterion, which is 0.7 ppb (1 percent of a 70 ppb NAAQS). In 2023 there were 27 linked states for the 2015 ozone NAAQS: Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

[158] The EPA discussed its legal authority for and the technical viability of generation shifting as a method of emissions reduction under the good neighbor provision in the CSAPR Update. *See especially* 81 FR 74504, 74545–47; *see also* CSAPR Update Response to Comment Document at 546–550 (legal authority); *id.* 528–533 (technical feasibility). *See* Final Revised CSAPR Update, 86 FR 23096–97.

[159] The EPA also noted in the CSAPR Update, ''Interpreting the Good Neighbor Provision to be sufficiently broad to authorize reliance on generation shifting is also consistent with the legislative history for the 1970 CAA Amendments. The Senate Report stated that to achieve the NAAQS, '[g]reater use of natural gas for electric power generation may be required,' S. Rep. No. 91–1196 at 2.'' 81 FR 74545 n.141.

[160] The feasibility of the timetable for emissions reductions from both EGUs and non-EGUs is further addressed in Section VII.A of this proposed rule.

[161] The EPA used the Revised CSAPR Update air quality modeling for this screening assessment because the air quality modeling for this proposed rule was not completed in time to support the assessment.

To analyze non-EGU emissions units, the EPA aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICS. Then for linked states, the EPA followed the 2-step process below:

Step 1—The EPA identified industries whose potentially controllable emissions have the greatest ppb impact on downwind air quality, and

Step 2—The EPA determined which of the most impactful industries and emissions units had the most emissions reductions that would make meaningful air quality improvements at the downwind receptors at a marginal cost threshold the EPA determined using underlying control device efficiency and cost information.

To estimate the contributions by industry, defined by 4-digit NAICS, at each downwind receptor the EPA used the 2023 state-receptor specific Revised CSAPR Update ppb/ton values and the Revised CSAPR Update calibration factors used in the air quality assessment tool (AQAT) for control analyses in 2023.[162] The EPA focused on assessing emissions units that emit greater than 100 tons per year (tpy) of NO_X.[163] By limiting the focus to potentially controllable emissions, well-controlled sources that still emit greater than 100 tpy are excluded. Instead, the focus is on uncontrolled sources or sources that could be better controlled at a reasonable cost. As a result, reductions from any industry identified by this process are more likely to be achievable and to lead to air quality improvements.

From this information, the EPA prepared a summary with the estimated total, maximum, and average contributions from each industry and the number of receptors with contributions greater than or equal to 0.01 ppb from each industry.[164] The EPA used this information to identify breakpoints in the data to determine which industries to focus on for the next steps in its analysis, as described in the Non-EGU Screening Assessment memorandum.

A review of the maximum contribution data indicated that the EPA should focus the assessment of NO_X reduction potential and cost primarily on four industries. These industries each (1) have a maximum contribution to any one receptor of greater than 0.10 ppb and (2) contribute greater than or equal to 0.01 ppb to at least 10 receptors. The four industries identified below comprise the ''Tier 1'' non-EGU industries.

- Pipeline Transportation of Natural Gas
- Cement and Concrete Product Manufacturing
- Iron and Steel Mills and Ferroalloy Manufacturing
- Glass and Glass Product Manufacturing

In addition to these industries, the maximum contribution data suggests including five additional industries as a second tier in the assessment. These industries each either have (1) a maximum contribution to any one receptor greater than or equal to 0.10 ppb but contribute greater than or equal to 0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution less than 0.10 ppb but contribute greater than or equal to 0.01 ppb to at least 10 receptors. The five industries identified below comprise the ''Tier 2'' non-EGU industries.

- Basic Chemical Manufacturing
- Petroleum and Coal Products Manufacturing
- Metal Ore Mining
- Lime and Gypsum Product Manufacturing
- Pulp, Paper, and Paperboard Mills

For additional discussion of the contribution information, see Appendix A of the Non-EGU Screening Assessment memorandum included in the docket for this proposed rulemaking.

Next, to identify an annual cost threshold for evaluating potential emissions reductions in the Tier 1 and Tier 2 industries, the EPA used the Control Strategy Tool (CoST),[165] the Control Measures Database (CMDB),[166] and the projected 2023 emissions inventory to prepare a listing of potential control measures, and costs, applied to non-EGU emissions units in the projected 2023 emissions inventory. Using these data, the EPA plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments. Figure 1 on page 4 of the Non-EGU Screening Assessment memorandum, which is available in the docket for this proposed rulemaking, indicates there is a ''knee in the curve'' at approximately $7,500 per ton (all non-EGU cost estimates in the assessment and presented in the rest of this section are in 2016 dollars). The EPA used this marginal cost threshold to further assess potential control strategies, estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries. Note that controls and related emissions reductions are available at several estimated cost levels up to the $7,500 per ton threshold. (These costs do not include monitoring, recordkeeping, reporting, or testing costs.)

Next, using the marginal cost threshold of $7,500 per ton, to estimate emissions reductions and costs the EPA processed the CoST run using the maximum emissions reduction algorithm,[167] with known controls.[168] The EPA identified controls for non-EGU emissions units in the Tier 1 and Tier 2 industries that cost up to $7,500 per ton. The EPA then calculated air quality impacts associated with the estimated reductions for the 27 linked states in 2023 using the following steps.

1. The EPA binned the estimated reductions by 4-digit NAICS code into the Tier 1 and Tier 2 industries.

2. The EPA used the 2023 state-receptor specific Revised CSAPR Update ppb/ton values and the Revised CSAPR Update calibration factors used in the AQAT for control analyses in 2023. The EPA multiplied the estimated

[162] The calibration factors are receptor-specific factors. For the Revised CSAPR Update, the calibration factors were generated using 2016 base case and 2023 base case air quality model runs. These receptor-level ppb/ton factors are discussed in the Ozone Transport Policy Analysis Final Rule TSD found here: *https://www.epa.gov/sites/default/files/2021-03/documents/ozone_transport_policy_analysis_final_rule_tsd_0.pdf.*

[163] In the non-EGU emissions reduction assessment prepared for the Revised Cross State Air Pollution Rule Update (*https://www.regulations.gov/document/EPA-HQ-OAR-2020-0272-0014*), The EPA reviewed emissions units with >150 tpy of NO_X emissions. In this assessment, EPA broadened the scope to include emissions units with greater than or equal to 100 tpy of NO_X emissions.

[164] The EPA chose to include in the Non-EGU NO_X reduction potential analysis those industries that contribute at least 0.01 ppb to a downwind receptor in order to focus the analysis on the most impactful industries. The 0.01 criterion is based on an analysis of the distribution and relative magnitude of contributions from 41 industries, as identified in the Non-EGU Screening Assessment memorandum. From this analysis the EPA determined that 0.01 ppb provides a meaningful conservative breakpoint for screening out non-impactful industries from the Non-EGU analysis in this proposed rule. Details on this analysis that provides the basis for using 0.01 ppb can be found in the Non-EGU Screening Assessment memorandum.

[165] Further information on CoST can be found at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

[166] The CMDB is available at the following link: *https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.*

[167] The maximum emissions reduction algorithm assigns to each source the single measure (if a measure is available for the source) that provides the maximum reduction to the target pollutant. For more information, *see* the CoST User's Guide available at the following link: h*ttps://www.cmascenter.org/cost/documentation/3.7/CoST%20User's%20Guide/.*

[168] Known controls are well-demonstrated control devices and methods that are currently used in practice in many industries. Known controls do not include cutting edge or emerging pollution control technologies.

non-EGU reductions by the ppb/ton values and by the receptor-specific calibration factor to estimate the ppb impacts from these emissions reductions.

Next, because boilers represent the majority emissions units in the Tier 2 industries for which there were controls that cost up to $7,500 per ton, the EPA further targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers. To identify potentially impactful boilers, using the projected 2023 emissions inventory in the linked upwind states, the EPA identified a universe of boilers with greater than 100 tpy NO_X emissions that had contributions at downwind receptors.[169] [170] The EPA refined the universe of boilers to a subset of impactful boilers by sequentially applying the three criteria below to each boiler. This approach is similar to the overall analytical framework and was tailored for application to individual boilers.[171]

- Criterion 1—Estimated maximum air quality contribution at an individual receptor of greater than or equal to 0.0025 ppb or estimated total contribution across downwind receptors of greater than or equal to 0.01 ppb.
- Criterion 2—Controls that cost up to $7,500 per ton.
- Criterion 3—Estimated maximum air quality improvement at an individual receptor of greater than or equal to 0.001 ppb.

Lastly, the EPA updated its analytical framework to the 2026 analytic year by which the EPA is proposing non-EGU controls be installed across the Tier 1 and Tier 2 industries and various emissions unit types. The EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD,[172] that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season. The EPA prepared the non-EGU screening assessment for the year 2026 by generally applying the analytical framework detailed above, with some modifications. The updated screening assessment results for 2026 are discussed in Section VI.C.2 [173] of this proposed rule. Specifically, the EPA

- Retained the impactful industries identified in Tier 1 and Tier 2, the $7,500 cost per ton threshold, and the methodology for identifying impactful boilers;
- Modified the framework to address challenges associated with using the projected 2023 emissions inventory by using the 2019 emissions inventory; [174] and
- Updated the air quality modeling data by using the most recent air quality modeling data for this proposal for the analytic year 2026.

3. Other Stationary Sources NO_X Mitigation Strategies

As part of its analysis for this proposed rule, the EPA also reviewed whether NO_X mitigation strategies for any other stationary sources may be appropriate. In this section, the EPA discusses three classes of units that have historically been excluded from our interstate air transport programs: (1) Units less than or equal to 25 MW, (2) solid waste incineration units, and (3) cogeneration units. EPA's initial assessment does not lead it to propose inclusion of the units less than or equal to 25 MW, but the EPA is requesting comment on any particular units within this category that may offer cost-effective reduction potential. The EPA is also taking comment on and considering whether to include emissions limitations for solid waste incineration units (many of which are less than 25 MW) in a final rule, as discussed later. For cogeneration units previously exempted from EGU emissions budgets established through ozone interstate transport rules, the EPA has not identified a basis for inclusion in this proposal.

The EPA has not historically identified substantial emissions reduction or air quality gains from corresponding reductions from these segments of units and has therefore not considered inclusion of these segments of stationary sources in its federal programs for interstate transport.

However, given the need to implement a full remedy to address interstate transport, the more stringent 2015 ozone NAAQS of 70 ppb, and the extended period of time for which the EPA projects upwind contribution to persistent nonattainment and maintenance problems, the EPA is requesting comment on whether sources within these three segments—units serving a generator equal or smaller than 25 MW, cogeneration units, and solid waste incineration units—could merit inclusion within EPA's proposed NO_X mitigation strategy in this rule. Specifically, the EPA requests comment on available NO_X mitigation technologies, NO_X emissions rate performance, total potentially available NO_X reductions, installation timing, cost, air quality impacts, source-specific information, and any other information that could inform a control determination specific to these three types of units. The EPA provides an assessment of these three segments, their emissions control opportunities, and potential air quality benefits below. Additional considerations are further discussed in the EGU NO_X Mitigation Strategies Proposed Rule TSD.

a. Units Less Than or Equal to 25 MW

The EPA has historically not included control requirements for emissions for units less than or equal to 25 MW for three primary reasons: Low potential reductions, relatively high cost per ton of reduction, and high monitoring and other compliance burdens. In the January 11, 1993, Acid Rain permitting rule, the EPA provided for a conditional exemption from the emissions reduction, emitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05% by weight, because of the *de minimis* nature of their potential SO_2, CO_2 and NO_X emissions. *See* 63 FR 57484. The NO_X SIP Call identified these as *Small Point Sources.* For the purposes of that rulemaking, the EPA considered electricity generating boilers and turbines serving a generator 25 MWe or less, to be small point sources. The EPA noted that the collective emissions from small sources

[169] The EPA used the 2023fj non-EGU point source inventory files from the 2016v2 emissions platform.

[170] Maryland, Missouri, Nevada, and Wyoming did not have boilers with >100 tpy NO_X emissions.

[171] For the impactful boiler assessment, the estimated air quality contributions and improvements were not based on modeling of individual emissions units or emissions source sectors. The air quality estimates were derived by using the 2023 state/receptor specific Revised CSAPR Update ppb/ton values and the Revised CSAPR Update calibration factors used in AQAT. The results indicate a level of precision not supported by the underlying air quality modeling. The results were intended to provide an indication of the relative impact across sources.

[172] Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD (''CSAPR Update Non-EGU TSD''), August 2016, available at *https://www.epa.gov/csapr/assessment-non-egu-NOX-emission-controls-cost-controls-and-time-compliance-final-tsd.*

[173] The non-EGU screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. For more detailed discussion of these issues, *see* Section VII.C of this proposed rule and the Non-EGU Sectors TSD included in the docket.

[174] The EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. *See* the Non-EGU Screening Assessment memorandum, available in the docket, for a discussion of the challenges associated with using the projected 2023 emissions inventory.

were relatively small and the administrative burden to the states and regulated entities of controlling such sources was likely to be considerable. As a result, the rule did not assume reductions from those sources in state emissions budgets requirements (63 FR 57402). Similar size thresholds have been incorporated in subsequent transport programs such as CAIR and CSAPR. As these sources were not identified as having cost-effective reductions and so were not included in those programs, they were also exempted from certain reporting requirements and the data for these sources is, therefore, not of the same caliber as that of covered larger sources.

EPA's preliminary survey of current data, compared to this initial justification, does not appear to offer a compelling reason to depart from this past practice by requiring emission reductions from these small EGU sources as part of this rule. For instance, as explained in the EGU NO_X Mitigation Strategies Proposed Rule TSD, EPA has evaluated the costs of SCR retrofits at small EGUs using its Retrofit Cost Analyzer and found that such controls become markedly less cost-effective at lower levels of generating capacity. This analysis concluded that, after controlling for all other unit characteristics, the dollar per ton cost for a SCR retrofit increases by about a factor of 2.5 when moving from a 500 MW to a 10 MW unit, and a factor of 8 when moving to a 1 MW unit.[175] Moreover, the EPA estimates that under 6% of nationwide EGU emissions come from units less than 25 MW and not covered by current applicability criteria due to this size exemption threshold. Therefore, the EPA is not proposing to require any emissions reductions from these units, but the EPA requests comment on whether there are any cost-effective reductions and corresponding air quality benefits to nonattainment or maintenance receptors from any units within this segment.

b. Municipal Solid Waste Units

The EPA seeks comment on whether NO_X emissions reductions should be sought from municipal solid waste combustor units (MWCs) to address interstate ozone transport. As noted below, MWCs emit substantial amounts of NO_X, and some states have required emissions limits for these facilities that are more stringent than the federal requirements contained within EPA's new source performance standard (NSPS) for this industry. These more stringent limits, if applied broadly to the 26 states included in this proposed FIP action, would create an additional means of reducing NO_X emissions.

MWCs burn garbage and other non-hazardous solid material using a variety of combustion techniques. Section 2.1, Refuse Combustion, of the EPA emissions factor reference document AP–42[176] contains a description of the seven different combustion process technologies most commonly used in the industry. A copy of Section 2.1 of AP–42 is included within the Docket for this proposed rule. These seven combustion processes are as follows: Mass burn waterwall, mass burn rotary waterwall, mass burn refractory wall, refuse-derived fuel-fired, fluidized bed, modular starved air, and modular excess air. Section 2.1 of AP–42 contains detailed process descriptions of each of these MWC processes. During the combustion process, a number of pollutants are produced, including NO_X, which forms through oxidation of nitrogen in the waste and from fixation of nitrogen in the air used to burn the waste. NO_X emissions from MWCs are typically released through tall stacks which enables the emissions to be transported long distances.

Most MWCs are cogeneration facilities that recover heat from the combustion process to power a turbine to produce electricity. According to a 2018 report from the Energy Recovery Council,[177] 72 of the 75 operating MWC facilities in the U.S. produce electricity from heat captured from the combustion process. The electrical output of MWCs is relatively small compared to the EGUs that will be regulated per the proposed requirements of Section VII.B of this proposal, with most MWCs having an electrical output capacity of less than 25 MW. The Non-EGU Sectors TSD located in the Docket identifies the electrical output capacity for MWC units that produce electricity as reflected in EPA's NEEDS database.

However, despite their relatively small electricity-generating potential, NO_X emissions from MWCs located in the transport states identified in this proposal are substantial. According to the EPA's NEI database, MWCs emitted 19,222 tons of NO_X in 2017 in the ten states included in this proposal that contain them. Table 8 of the Non-EGU Sectors TSD contains a list of MWC facilities located within the states included in this proposal along with their NO_X emissions as reported to the NEI.

The EPA has promulgated NO_X emissions limits for large MWCs, defined as those that process 250 tons of municipal solid waste per day or more at 40 CFR part 60, subpart Cb and 40 CFR part 60, subpart Eb. Subpart Cb is applicable to MWCs that commenced construction on or before September 20, 1994, while Subpart Eb is applicable to MWCs that commenced construction, modification, or reconstruction after September 20, 1994. The NO_X limits for subpart Cb are found within Tables 1 and 2 of 40 CFR 60.39b and range from 165 to 250 ppm depending on the combustor design type. The NO_X limits for Subpart Eb are found at 40 CFR 60.52b(d) and are 180 ppm during a unit's first year of operation and drop to 150 ppm afterwards, applicable across all combustor types. These limits correspond to NO_X emissions rates of 0.31 and 0.26 lbs/MMBtu, respectively.

Section 182(b)(2) and (f) of the CAA requires states with ozone nonattainment areas classified as Moderate or higher to adopt regulations with control requirements representing reasonably available control technology (RACT) for major sources of VOCs and NO_X. Sections 184(b)(1)(B) and 182(f) of the Act require RACT requirements be adopted in all areas included within the Ozone Transport Region (OTR). Due primarily to the NO_X RACT requirement, many states within the Northeast located within the OTR have adopted NO_X emissions limits for MWCs that are more stringent than what would otherwise be required by EPA's NSPS or the emissions guideline for these units. For example, the Montgomery County Resource Recovery Facility in Maryland is required to meet a NO_X RACT limit of 140 ppm (at 7 percent oxygen) on a 24-hour block average. Additionally, MWC facilities located in Virginia operated by Covanta, Inc., are required to meet a NO_X RACT limit of 110 ppm (at 7 percent oxygen) on a 24-hour basis, and a limit of 90 ppm (at 7 percent oxygen) on an annual average basis.[178] The 110 ppm limit equates to a limit of 0.19 lbs/MMBtu.

The Ozone Transport Commission (OTC) issued a report entitled ''Municipal Waste Combustor Workgroup Report'' in June of 2021. The

[175] Preliminary estimate based on representative coal units with starting NO_X rate of 0.2 lb/mmBtu, 10,000 BTU/kwh, and assuming 80 percent reduction.

[176] ''AP–42, Fifth Edition Compilation of Air Pollutant Emissions Factors, Volume 1: Stationary Point and Area Sources'', available at: *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.*

[177] ''2018 Directory of Waste to Energy Facilities''; Energy Recovery Council.

[178] The NO_X permit limits for the Montgomery County facility and the Virginia facilities can be found within the OTC's Municipal Waste Combustor Workgroup Report included within the Docket for this proposed rule.

report is included within the docket for this proposal.[179] The report notes that MWCs are a significant source of NO_X emissions in the OTR, releasing approximately 22,000 tons of NO_X from facilities within 9 OTR states in 2018. The report summarizes the results of a literature review of state-of-the-art NO_X controls that have been successfully installed and concludes that significant reductions could be achieved using several different technologies described in the report, primarily via combustion modifications made to MWC units already equipped with SNCR. The MWC workgroup evaluated the emissions reduction potential from two different control levels, one based on a NO_X concentration in the effluent of 105 to 110 ppm, and another based on a limit of 130 ppm. The workgroup's findings were that a control level of 105 parts per million by volume, dry (ppmvd) on a 30-day average basis and a 110 ppmvd on a 24-hour averaging period would reduce NO_X emissions from MWCs by approximately 7,300 tons annually, and that a limit of 130 ppmvd on a 30 day-average could achieve a 4,000 ton reduction. The report notes that 8 MWC units exist that are already subject to permit limits of 110 ppm, 7 in Virginia, and one in Florida. Studies evaluating MWCs similar in design to the large MWCs in the OTR found NO_X reductions could be achieved at costs ranging from $2,900 to $6,600 per ton of NO_X reduced. Based on the findings of this report, the Commissioners of the states within the OTR adopted a resolution to develop a recommendation for emissions reductions from MWCs during their June 15, 2021, annual public meeting.[180]

In light of the above, the EPA requests comment on whether NO_X limits for MWCs located in the states covered by this proposed rule should be included in the final FIP. Specifically, if NO_X controls are included in the final FIP, the EPA requests comment on the following issues:

- What NO_X emissions limit and averaging time should MWCs be required to meet, and in particular should the EPA adopt emissions rates of 105 ppmvd on a 30-day averaging basis and 110 ppmvd on a 24-hour averaging basis?
- What types of NO_X control technology could be used to reduce NO_X emissions at MWCs, and in particular should the EPA adopt the combustion control modifications made to units with previously installed SNCR identified by the MWC workgroup?
- Whether there is information that would call into question the OTC workgroup's estimated cost of controls for reducing NO_X emissions from MWCs of $2,900 to $6,600 per ton, and, assuming that range is accurate, whether there is any justification for not requiring these controls in light of their relative cost-effectiveness and total level of reductions available, which compare favorably with the proposed EGU and non-EGU control strategies?
- If the final FIP includes emissions reduction requirements for MWCs, should any mechanism be available by which a particular MWC source could seek to establish that meeting the required emissions limits is not feasible?
- Is there any evidence that retrofit of MWC emissions controls would take longer to implement than the 2026 ozone season?
- Would it be appropriate to rely on existing testing, monitoring, recordkeeping, and reporting requirements for MWCs under the applicable NSPS or other requirements?

c. Cogeneration Units

Consistent with prior transport rules, fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy (generally referred to as ''cogeneration units'') and that meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program would be subject to the emissions reduction requirements established in this rulemaking for EGUs. However, those applicability criteria—which the EPA is not proposing to alter in this rulemaking (*see* Section VII.B.3 of this proposed rule)—exempt some cogeneration units from coverage as EGUs under the trading program. The EPA is proposing that fossil fuel-fired boilers and combustion turbines that produce both electricity and useful thermal energy and that do not meet the applicability criteria to be included in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs would not be subject to any other emissions reduction requirements under this rulemaking.

Cogeneration systems can offer considerable environmental benefit as they often require less fuel to produce a given energy output. The average efficiency of fossil-fuel fired power plants in the United States is 33 percent. This means that two-thirds of the energy used to produce electricity at most power plants in the United States is wasted in the form of heat discharged to the atmosphere. By recovering wasted heat, combined heat and power (CHP) systems at cogeneration units typically achieve total system efficiencies of 60 to 80% for producing electricity and useful thermal energy. Some systems achieve efficiencies approaching 90%. This increased efficiency allows the same level of energy use to be achieved with fewer criteria-pollutant and greenhouse gas emissions. Additionally, these systems increase the reliability of access to electrical power for the facilities they serve and reduce the need for electricity from regional power plants and their associated transmission and distribution networks.

According to information contained in the EPA's Combined Heat and Power Partnership's document ''Catalog of CHP Technologies'',[181] there are 4,226 CHP installations in the U.S. providing 83,317 MWe of electrical capacity. Over 99% of the installations are powered by 5 equipment types, those being reciprocating engines (52 percent), boilers/steam turbines (17 percent), gas turbines (16 percent), microturbines (8 percent), and fuel cells (4 percent). The majority of the electrical capacity is provided by gas turbine CHP systems (64 percent) and boiler/steam turbine CHP systems (32 percent). The various CHP technologies described above are available in a large range of sizes, from as small as 1 kilowatt reciprocating engine systems to as large as 300 megawatt gas turbine powered systems.

NO_X emissions from fuel cell powered systems are negligible, and NO_X emissions from rich-burn reciprocating engine, gas turbine, and microturbine systems are low, ranging from 0.013 to 0.05 lbs/mmBTU. NO_X emissions from lean-burn reciprocating engine systems and gas-powered steam turbines systems range from 0.1 to 0.2 lbs/mmBTU. The highest NO_X emitting CHP units are solid fuel-fired boiler/steam turbine systems which emit NO_X at rates ranging from 0.2 to 1.2 lbs/mmBTU. A preliminary assessment from EPA's IPM Summer 2021 Reference Case model suggest that cogeneration units exempted from current EPA EGU transport programs due to such classification are projected to account for approximately 5% of nationwide summer NO_X emissions in 2023.[182]

[179] This report is also available at *https://otcair.org/upload/Documents/Reports/20210624%20OTC%20SAS%20MWC%20report%20final.pdf.*

[180] *See* ''Notice of Proposed rules Taken by Ozone Transport Commission At Annual Public Meeting, June 15, 2021'' included in the Docket for this proposed rule.

[181] This document is available at*: https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf.*

[182] *https://www.epa.gov/airmarkets/results-using-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.* The EPA notes that cogeneration units not exempted from EGU Air programs are included in the EPA assessment of

Under the proposed rule (consistent with prior CSAPR rulemakings), certain cogeneration units would be exempt from coverage under the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs. Specifically, the trading program regulations include an exemption for a unit that qualifies as a cogeneration unit throughout the later of 2005 or the first 12 months during which the unit first produces electricity and continues to qualify through each calendar year ending after the later of 2005 or that 12-month period and that meets the limitation on electricity sales to the grid. In order to meet the trading program's definition of ''cogeneration unit'' under the regulations, a unit (*i.e.,* a fossil-fuel-fired boiler or combustion turbine) must be a topping-cycle or bottoming-cycle type that operates as part of a ''cogeneration system.'' A cogeneration system is defined as an integrated group of equipment at a source (including a boiler, or combustion turbine, and a generator) designed to produce useful thermal energy for industrial, commercial, heating, or cooling purposes and electricity through the sequential use of energy. A topping-cycle unit is a unit where the sequential use of energy results in production of useful power first and then, through use of reject heat from such production, in production of useful thermal energy. A bottoming-cycle unit is a unit where the sequential use of energy results in production of useful thermal energy first, and then, through use of reject heat from such production, in production of useful power. In order to qualify as a cogeneration unit, a unit also must meet certain efficiency and operating standards in 2005 and each year thereafter. The electricity sales limitation under the exemption is applied in the same way whether a unit serves only one generator or serves more than one generator. In both cases, the total amount of electricity produced annually by a unit and sold to the grid cannot exceed the greater of one-third of the unit's potential electric output capacity or 219,000 MWh. This is consistent with the approach taken in the Acid Rain Program (40 CFR 72.7(b)(4)), where the cogeneration-unit exemption originated.

The EPA is requesting comment on the proposal to exempt cogeneration units meeting the above criteria from any emissions reduction requirements under this proposed rulemaking. The EPA also requests comment on the alternative of requiring fossil fuel-fired boilers in the non-EGU industries identified earlier (Section VI.B.2.a of this proposed rule) that serve electricity generators and that qualify for an exemption from inclusion in the CSAPR NO_X Ozone Season Group 3 Trading Program as EGUs to instead meet the same emissions standards, if any, that would apply under this proposed rulemaking to fossil fuel-fired boilers at facilities in the same non-EGU industries that do not serve electricity generators. These proposed emissions standards are set forth in Section VII.C.5 of this proposed rule. Cogeneration units at these facilities are in the non-EGU industries identified in EPA's non-EGU screening assessment for this proposal (although potential emissions reductions from such cogeneration units were not specifically quantified in the assessment). Under this alternative approach, to the extent these industries have otherwise been determined in this proposal to significantly contribute to nonattainment or interfere with maintenance, the EPA would find that cogeneration units in these industries should not be excluded from EPA's overall NO_X mitigation strategy.

4. Mobile Source NO_X Mitigation Strategies

Under a variety of CAA programs, the EPA has established federal emissions and fuel quality standards that reduce emissions from cars, trucks, buses, nonroad engines and equipment, locomotives, marine vessels, and aircraft (*i.e.,* ''mobile sources''). Because states are generally preempted from regulating new vehicles and engines with certain exceptions (*see generally* CAA sections 209, 177), mobile source emissions are primarily controlled through EPA's federal programs. The EPA has been regulating mobile source emissions since it was established as a federal agency in 1970, and all mobile source sectors are currently subject to NO_X emissions standards. The EPA factors these standards and associated emissions reductions into its baseline air quality assessment in good neighbor rulemaking, including in this proposed rule. These data are factored into EPA's analysis at Steps 1 and 2 of the 4-step framework. As a result of this long history, NO_X emissions from onroad and nonroad mobile sources have substantially decreased (73 percent and 57 percent since 2002, for onroad and nonroad, respectively) [183] and are predicted to continue to decrease into the future as newer vehicles and engines that are subject to the most recent, stringent standards replace older vehicles and engines.[184]

For example, in 2014, the EPA promulgated new, more stringent emissions and fuel standards for light-duty passenger cars and trucks.[185] The fuel standards took effect in 2017, and the vehicle standards phase in between 2017 and 2025. Other EPA actions that are continuing to reduce NO_X emissions include the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002; January 18, 2001); the Clean Air Nonroad Diesel Rule (69 FR 38957; June 29, 2004); the Locomotive and Marine Rule (73 FR 25098; May 6, 2008); the Marine Spark-Ignition and Small Spark-Ignition Engine Rule (73 FR 59034; October 8, 2008); the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder Rule (75 FR 22895; April 30, 2010); and the Aircraft and Aircraft Engine Emissions Standards (77 FR 36342; June 18, 2012).

The EPA is currently developing a new regulatory effort to reduce NO_X and other pollution from heavy-duty trucks (known as the Cleaner Trucks Initiative), as described in the January 21, 2020, Advance Notice of Proposed Rulemaking (85 FR 3306). Heavy-duty vehicles are the largest contributor to mobile source emissions of NO_X and will be one of the largest mobile source contributors to ozone in 2025.[186] Reducing heavy-duty vehicle emissions nationally would improve air quality where the trucks are operating as well as downwind. As required by CAA section 202(a)(3)(A) of the Act, the EPA will be proposing NO_X emissions standards that ''reflect the greatest degree of emissions reduction achievable through the application of technology which the Administrator determines will be available for the model year to which such standards apply, giving appropriate consideration to cost, energy, and safety factors associated with the application of such technology.'' Section 202(a)(3)(C) of the Act requires that standards apply for no less than 3 model years and apply no earlier than 4 years after promulgation.

The EPA's existing regulatory program for mobile sources will

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EGU reduction potential in Section VI.B.1 of this proposed rule.

[183] US EPA. Our Nation's Air: Status and Trends Through 2019. *https://gispub.epa.gov/air/trendsreport/2020/#home.*

[184] National Emissions Inventory Collaborative (2019). 2016v1 Emissions Modeling Platform. Retrieved from *http://views.cira.colostate.edu/wiki/wiki/10202.*

[185] Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emissions and Fuel Standards, 79 FR 23414 (April 28, 2014).

[186] Zawacki et al., 2018. Mobile source contributions to ambient ozone and particulate matter in 2025. Atmospheric Environment. Vol 188, pg 129–141. Available online: *https://doi.org/10.1016/j.atmosenv.2018.04.057.*

continue to reduce NO_X emissions into the future, and the EPA is currently taking active steps to ensure that these NO_X reductions occur. The CAA prohibits tampering with emissions controls, as well as manufacturing, selling, and installing aftermarket devices intended to defeat those controls. The EPA currently has a National Compliance Initiative called ''Stopping Aftermarket Defeat Devices for Vehicles and Engines,'' which focuses on stopping the manufacture, sale, and installation of hardware and software specifically designed to defeat required emissions controls on onroad and nonroad vehicles and engines.

C. Control Stringencies Represented by Cost Threshold ($ per Ton) and Corresponding Emissions Reductions

1. EGU Emissions Reduction Potential by Cost Threshold

For EGUs, as discussed in Section VI.A of this proposed rule, the multi-factor test considers increasing levels of uniform control stringency in combination with considering total NO_X reduction potential and corresponding air quality improvements. The EPA evaluated EGU NO_X emissions controls that are widely available (described previously in Section VI.B.1 of this proposed rule), that were assessed in previous rules to address ozone transport, and that have been incorporated into state planning requirements to address ozone nonattainment.

The EPA evaluated the EGU sources within the state of California and found there were no covered coal steam sources greater than 100 MW that would have emissions reduction potential according to EPA's assumed EGU SCR retrofit mitigation technologies.[187] The EGUs in the state are sufficiently well-controlled resulting in the lowest fossil-fuel emission rate and highest share of renewable generation among the 26 states examined at Step 3. EPA's Step 3 analysis, including analysis of the emissions reduction factors from EGU sources in the state, therefore resulted in no additional emission reductions required to eliminate significant contribution from any EGU sources in California.

The tables below summarize the emissions reduction potentials (in ozone season tons) from these emissions controls across the affected jurisdictions. Table VI.C.1–1 focuses on near-term emissions controls while Table VI.C.1–2 includes emissions controls with extended implementation timeframes.

TABLE VI.C.1–1—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (tons)—2023

State	Baseline 2023 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion			
		SCR optimization	SCR optimization + combustion control upgrades *	SCR/SNCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades + generation shifting
Alabama	6,648	32	156	156	387
Arkansas	8,955	28	28	28	66
Delaware	423	35	35	39	35
Illinois	7,662	70	70	247	120
Indiana	12,351	856	856	865	1,191
Kentucky	13,900	446	1,047	1,047	2,260
Louisiana	9,987	579	579	675	579
Maryland	1,208	0	0	8	13
Michigan	10,737	4	4	19	4
Minnesota	4,207	98	98	139	246
Mississippi	5,097	73	697	697	697
Missouri	20,094	7,345	7,345	7,569	8,013
Nevada	2,346	66	66	66	66
New Jersey	915	105	105	105	116
New York	3,927	64	64	64	164
Ohio	10,295	1,161	1,161	1,161	1,926
Oklahoma	10,463	199	890	890	890
Pennsylvania	12,242	2,878	2,878	2,978	3,287
Tennessee	4,319	110	110	110	85
Texas	40,860	921	921	1,154	2,344
Utah	15,500	7	7	7	519
Virginia	3,415	164	242	296	271
West Virginia	14,686	554	1,099	1,380	1,927
Wisconsin	5,933	7	7	26	-50
Wyoming	10,191	82	677	690	1,648
Total	236,363	15,883	19,143	20,417	26,806

* The EPA shows reduction potential from state-of-the-art LNB upgrade as near-term reduction emissions controls, but explains in Section VI.B and VI.D of this proposed rule that this reduction potential would not be implemented until 2024 for states not included in the Revised CSAPR Update.

[187] The only coal-fired power plant in California is the 63 MW Argus Cogeneration facility in Trona, California.

TABLE VI.C.1–2—EGU OZONE-SEASON EMISSIONS AND REDUCTION POTENTIAL (tons)—2026

State	Baseline 2026 OS NO_X	Reduction potential (tons) for varying levels of technology inclusion				
		SCR optimization	SCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades	SCR/SNCR optimization + combustion control upgrades + SCR/SNCR retrofits	SCR/SNCR optimization + combustion control upgrades + SCR/SNCR retrofits + generation shifting
Alabama	6,701	32	156	156	916	916
Arkansas	8,728	28	28	28	4,697	4,805
Delaware	473	35	35	39	39	39
Illinois	7,763	70	70	247	1,298	1,648
Indiana	9,737	720	720	729	1,740	1,946
Kentucky	13,211	446	885	885	5,450	5,638
Louisiana	9,854	579	579	675	6,102	6,102
Maryland	1,208	0	0	8	8	19
Michigan	9,129	4	4	19	2,959	3,015
Minnesota	4,197	98	98	139	1,613	1,661
Mississippi	5,077	73	697	697	3,164	3,163
Missouri	18,610	7,345	7,345	7,569	11,237	11,364
Nevada	2,438	66	66	66	1,227	1,227
New Jersey	915	105	105	105	105	116
New York	3,927	64	64	64	589	689
Ohio	10,295	1,161	1,161	1,161	1,354	1,709
Oklahoma	10,283	199	890	890	5,968	6,008
Pennsylvania	11,738	2,737	2,737	2,837	4,510	4,919
Tennessee	4,064	81	81	81	81	81
Texas	39,186	921	921	1,154	15,817	17,240
Utah	9,679	7	7	7	7,076	7,059
Virginia	3,243	164	242	263	646	676
West Virginia	14,686	554	1,099	1,380	3,660	4,089
Wisconsin	3,628	7	7	26	54	155
Wyoming	10,249	82	677	690	5,669	5,759
Total	219,017	15,577	18,675	19,917	85,978	90,041

2. Non-EGU Emissions Reduction Potential—Cost Threshold Up to $7,500/ton

The EPA used the updated non-EGU screening assessment for 2026 to estimate emissions reduction potential from the Tier 1 and Tier 2 industries and non-EGU emissions units. The EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (*e.g.,* NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. These estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

To prepare the non-EGU screening assessment for 2026, the EPA applied the analytical framework detailed in Section VI.B.2 of this proposed rule. The assessment includes emissions units from the Tier 1 industries and impactful high-emitting boilers in Tier 2 Industries. Using the latest air quality modeling for 2026, the EPA identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, or 0.7 ppb. In 2026 there are 23 linked states for the 2015 ozone NAAQS: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

The EPA re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory.[188] The EPA specified CoST to allow replacing an existing control if a replacement control is estimated to be greater than 10% more effective than the existing control. The EPA did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control. Also, the EPA removed six facilities from consideration because they are subject to an existing consent decree, are shut down, or will shut down by 2026. For additional detail on the six facilities removed, see Appendix B in the Non-EGU Screening Assessment memorandum. Table VI.C.2–1 summarizes the estimated reductions, total ppb improvements across all receptors, and annual total and average annual costs (in 2016 dollars) and Table VI.C.2–2 below summarizes the estimated reductions by state.

[188] The EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term non-EGU emissions reductions.

TABLE VI.C.2–1—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS), TOTAL PPB IMPROVEMENTS ACROSS ALL DOWNWIND RECEPTORS, AND COSTS

Tier	Ozone season emissions reductions (East/West)	Total PPB improvement across all downwind receptors	Annual total cost (million 2016$) (average annual cost/ton)	Industries (# of emissions units >100 tpy in identified industries)
Tier 1 Industries with Known Controls that Cost up to $7,500/ton.	41,153 (37,972/3,181)	4.352	$356.6 ($3,610)	Cement and Concrete Product Manufacturing (47) Glass and Glass Product Manufacturing (44) Iron and Steel Mills & Ferroalloy Manufacturing (39) Pipeline Transportation of Natural Gas (307).
Tier 2 Industry Boilers with Known Controls that Cost up to $7,500/ton.	6,033 (5,965/68)	0.809	54.2 (3,744)	Basic Chemical Manufacturing (17) Petroleum and Coal Products Manufacturing (10) Pulp Paper, and Paperboard Mills (25).

TABLE VI.C.2–2—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS) BY UPWIND STATE * **

State	2019 OS NO_X emissions	OS NO_X reductions
AR	8,265	1,654
CA	14,579	1,666
IL	16,870	2,452
IN	19,604	3,175
KY	11,934	2,291
LA	35,831	6,769
MD	2,365	45
MI	18,996	2,731
MN	17,591	673
MO	9,109	3,103
MS	12,284	1,761
NJ	2,025	0
NV	2,418	0
NY	6,003	500
OH	19,729	2,790
OK	22,146	3,575
PA	15,861	3,284
TX	47,135	4,440
UT	6,276	757
VA	7,041	1,563
WI	6,571	2,150
WV	9,825	982
WY	10,335	826
Total	322,793	47,187

* In the non-EGU screening assessment, EPA estimated emissions reduction potential from the non-EGU industries and emissions units. The estimated emissions reductions by state in the table above are from the non-EGU screening assessment; for additional results from the non-EGU screening assessment, including estimated reductions by state and by industry, please see the Non-EGU Screening Assessment memorandum available in the docket.

** In the assessment, EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (*e.g.,* NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. These estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

In this section, EPA provides a summary of the control technologies applied and their average costs across all of the non-EGU emissions units included in the screening assessment. This summary reflects one approach to organizing this information, which the Agency finds reasonable based on the information available for this proposal. As discussed in Section VI.B.2 of this proposed rule, the number of different industries and emissions unit categories and types present a challenge to defining a single method to identify appropriate control technologies, measures or strategies, and related costs across non-EGU emissions units. Because of the number of industries and emissions unit types, the available information does not easily allow grouping estimated emissions reductions by cost per ton threshold for a few control technologies, measures, or strategies. Nonetheless, Table VI.C.2–3 below provides a summary of estimated reductions and average cost per ton values by control technology across all non-EGU emissions units included in the non-EGU screening assessment. The summary reflects fourteen control technologies applied by CoST across all emissions units in the non-EGU screening assessment. The average cost per ton values range from $585 to $6,300 per ton, all of which are below the marginal cost per ton threshold of $7,500 per ton. Note that the average cost per ton values are in 2016 dollars and reflect simple averages and not a percentile or other representative cost values from a distribution of cost estimates.

The Non-EGU Screening Assessment memorandum includes two other summaries of estimated reductions and average cost per ton values by technology across non-EGU emissions units. First, the memorandum includes a summary by control technology as applied across non-EGU emissions units grouped by the Tier 1 industries and impactful boilers in Tier 2 industries, which given this further disaggregation reflects 18 control technologies across the tiers applied by CoST. Second, the memorandum includes a summary by control technology across non-EGU emissions units grouped by the seven individual Tier 1 and 2 industries, which given this disaggregation reflects 26 control technologies across the industries applied by CoST.

TABLE VI.C.2–3—ESTIMATED EMISSIONS REDUCTIONS (OZONE SEASON TONS), ANNUAL TOTAL COST, AND AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS

Control technology	Ozone season emissions reductions	Average cost per ton
Adjust Air to Fuel Ratio and Ignition Retard	212	$2,393
Layered Combustion	12,706	5,457
Low NO_X Burner	231	3,773
Low NO_X Burner and Flue Gas Recirculation	200	4,288
Natural Gas Reburn	284	2,703
Non-Selective Catalytic Reduction	147	585
Non-Selective Catalytic Reduction or Layered Combustion	6,359	4,743
Oxygen Enriched Air Staging	52	764
SCR + DLN Combustion	136	6,301
Selective Catalytic Reduction	12,239	2,543
Selective Catalytic Reduction and Steam Injection	929	3,787
Selective Non-Catalytic Reduction	8,076	1,485
Ultra-Low NO_X Burner	1,670	2,890
Ultra-Low NO_X Burner and Selective Catalytic Reduction	3,946	4,114

Refer to the Non-EGU Screening Assessment memorandum for additional 2026 screening assessment results—including by industry and by state, estimated emissions reductions and costs, as well as by industry, emissions source groups, control technologies, number of emissions units, estimated ozone season reductions, and annual total cost.

D. Assessing Cost, EGU and Non-EGU NO_X Reductions, and Air Quality

To determine the emissions that are significantly contributing to nonattainment or interfering with maintenance, the EPA applied the multi-factor test to EGUs and non-EGUs separately, considering for each the relationship of cost, available emissions reductions, and downwind air quality impacts. Specifically, for each sector, the EPA proposes a determination regarding the appropriate level of uniform NO_X control stringency that would collectively eliminate significant contribution to downwind nonattainment and maintenance receptors. The EPA also evaluated whether the proposed rule resulted in possible over-control scenarios by evaluating if an upwind state is linked solely to downwind air quality problems that could have been resolved at a lower cost threshold, or if an upwind state could have reduced its emissions below the 1 percent air quality contribution threshold at a lower cost threshold.

1. EGU Assessment

For EGUs, the EPA examined the emissions reduction potential associated with each EGU emissions control technology (presented in Section VI.C.1 of this proposed rule) and its impact on the air quality at downwind receptors. Specifically, EPA identified and assessed the projected average air quality improvements relative to the base case and whether these improvements are sufficient to shift the status of receptors from projected nonattainment to maintenance or from maintenance to attainment. Combining these air quality factors, costs, and emissions reductions, the EPA identified a control stringency for EGUs that results in substantial air quality improvement from emissions controls that are available in the timeframe for which air quality problems at downwind receptors persist. For all affected jurisdictions, this control stringency reflects, at a minimum, the optimization of existing post-combustion controls and installation of state-of-the-art NO_X combustion controls, which are widely available at a representative marginal cost of $1,800 per ton. EPA's evaluation also shows that the effective emissions rate performance across affected EGUs consistent with realization of these mitigation measures does not over-control upwind states' emissions relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS.

Similarly, the EPA also identified installation of new SCR post-combustion controls at coal steam sources greater than or equal to 100 MW and for a more limited portion of the oil/gas steam fleet that had higher levels of emissions as components of the required control stringency. These SCR retrofits are widely available by the 2026 ozone season at $11,000 and $7,700 per ton respectively. For all but 3 of the affected states (Alabama, Delaware, and Tennessee—which are no longer linked in 2026 at Steps 1 and 2 in EPA's base case air quality modeling), EPA's evaluation also shows that the effective emissions rate performance across EGUs consistent with realization of these mitigation measures does not over-control upwind states' emissions in 2026 relative to either the downwind air quality problems to which they are linked at Step 1 or the 1 percent contribution threshold that triggers further evaluation at Step 3 of the 4-step framework for the 2015 ozone NAAQS (*see* the Ozone Transport Policy Analysis Proposed Rule TSD for details).

To assess downwind air quality impacts for the nonattainment and maintenance receptors identified in Section V.D of this proposed rule, the EPA evaluated the air quality change at that receptor expected from the progressively more stringent upwind EGU control stringencies that were available for that time period in upwind states linked to that receptor. This assessment provides the downwind ozone improvements for consideration and provides air quality data that is used to evaluate potential over-control situations.

To assess the air quality impacts of the various control stringencies at downwind receptors for the purposes of Step 3, the EPA evaluated changes resulting from the emissions reductions associated with the identified emissions controls in each of the upwind states, as well as assumed corresponding reductions of similar stringency in the downwind state containing the receptor to which they are linked. By applying these emissions reductions to the state containing the receptor, the EPA assumes that the downwind state will implement (if it has not already) an emissions control stringency for its sources that is comparable to the upwind control stringency identified here. Consequently, The EPA is accounting for the downwind state's share of a nonattainment or maintenance problem as a part of the over-control evaluation.[189]

For this assessment, the EPA used an ozone air quality assessment tool (ozone AQAT) to estimate downwind changes in ozone concentrations related to upwind changes in emissions levels. The EPA focused its assessment on the years 2023 and 2026 as they pertain to the last years for which ozone season emissions data can be used for purposes of determining attainment for the Moderate (2024) and Serious (2027) attainment dates. For each EGU emissions control technology, the EPA first evaluated the magnitude of the change in ozone concentrations at the nonattainment and maintenance receptors for each relevant year (*i.e.,* 2023 and 2026). Next, the EPA evaluated whether the estimated change in concentration would resolve the receptor's nonattainment or maintenance concern by lowering the average or maximum design values, respectively, below 71 ppb. For a complete set of estimates, see the Ozone Transport Policy Analysis Proposed Rule TSD or the ozone AQAT excel file.

For 2023, the EPA evaluated potential air quality improvements at the downwind receptors outside of California associated with available EGU emissions control technologies in that timeframe. The EPA determined for the purposes of Step 3 that the average air quality improvement at the receptors relative to the engineering analytics base case was 0.11 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs and combustion control upgrades. The EPA determined for the purposes of Step 3 that one receptor in Clark County, Nevada switches from maintenance to attainment with these mitigation strategies in place. Table VI.D.1–1 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT.

For 2026, the EPA determined that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.43 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, and new post-combustion control (SCR and SNCR) retrofits at eligible units are assumed to be implemented. The EPA determined for the purposes of Step 3 that in 2026, all but one of the receptors are expected to remain nonattainment or maintenance across these control stringencies, with one receptor in Douglas County, Colorado switching from maintenance to attainment with these mitigation strategies in place.[190] Table VI.D.1–2 summarizes the results of EPA's Step 3 evaluation of air quality improvements at the receptors included in the AQAT analysis. For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Proposed Rule TSD and to the Ozone AQAT included in the docket for this rule.

TABLE VI.D.1–1—AIR QUALITY AT THE 29 RECEPTORS IN 2023 FROM EGU EMISSIONS CONTROL TECHNOLOGIES[a b]

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade
040278011	Arizona	Yuma	70.53	70.53	72.25	72.24
080350004	Colorado	Douglas	72.35	72.28	72.96	72.89
080590006	Colorado	Jefferson	73.23	73.19	73.84	73.80
080590011	Colorado	Jefferson	74.41	74.38	75.13	75.09
090010017	Connecticut	Fairfield	73.11	73.14	73.82	73.85
090013007	Connecticut	Fairfield	74.45	74.44	75.37	75.36
090019003	Connecticut	Fairfield	76.30	76.29	76.51	76.50
090099002	Connecticut	New Haven	72.11	72.07	74.16	74.12
170310001	Illinois	Cook	70.02	70.02	73.90	73.89
170310032	Illinois	Cook	70.14	70.15	72.78	72.79
170310076	Illinois	Cook	69.64	69.65	72.49	72.49
170314201	Illinois	Cook	70.19	70.18	73.75	73.74
170317002	Illinois	Cook	70.42	70.33	73.37	73.29
320030075	Nevada	Clark	70.09	70.06	71.01	70.98
420170012	Pennsylvania	Bucks	71.09	71.03	72.63	72.57
480391004	Texas	Brazoria	71.71	71.29	73.89	73.45
481210034	Texas	Denton	71.20	71.03	73.06	72.89
482010024	Texas	Harris	76.92	76.55	78.48	78.10
482010055	Texas	Harris	72.50	72.14	73.54	73.17
482011034	Texas	Harris	72.07	71.67	73.32	72.91
482011035	Texas	Harris	69.69	69.31	73.32	72.92
490110004	Utah	Davis	73.65	73.59	75.91	75.85

[189] For EGUs, this analysis for the Connecticut receptors shows no EGU reduction potential from the emissions reduction measures identified given that state's already low-emitting fleet; however, EGU reductions were identified in Colorado and these reductions were included in the over-control analysis.

[190] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. This method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states in order to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states and the health and climate benefits from this proposal are discussed in Section IX of this proposed rule.

TABLE VI.D.1–1—AIR QUALITY AT THE 29 RECEPTORS IN 2023 FROM EGU EMISSIONS CONTROL TECHNOLOGIES [a] [b]—Continued

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade
490353006	Utah	Salt Lake	74.35	74.29	75.99	75.93
490353013	Utah	Salt Lake	75.27	75.21	75.78	75.72
490570002	Utah	Weber	71.35	71.29	73.29	73.23
490571003	Utah	Weber	71.24	71.19	72.16	72.11
550590019	Wisconsin	Kenosha	73.17	73.07	74.09	73.99
550590025	Wisconsin	Kenosha	69.62	69.46	72.69	72.52
551010020	Wisconsin	Racine	71.70	71.61	73.64	73.55
Average AQ Change Relative to Base (ppb)						0.11
Total PPB Change Across All Receptors Relative to Base [c]						3.08

Table Notes:

[a] These results reflect the inclusion of all identified LNB upgrade potential. Some of which will be implemented in 2023 state emissions budgets, and some be implemented in 2024 state emissions budgets (for those states not included in the Revised CSAPR Update).

[b] The EPA notes that the design values reflected in tables VI.D.1–1 and 2 correspond to the engineering analysis EGU emissions inventory that was used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Proposed Rule TSD.

[c] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section IX of this proposed rule provides a more complete picture of the air quality impacts of the proposed rule.

TABLE VI.D.1–2—AIR QUALITY AT RECEPTORS IN 2026 FROM EGU EMISSIONS CONTROL TECHNOLOGIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit	Baseline (engineering analysis)	SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit
40278011	Arizona	Yuma	70.11	70.09	71.81	71.79
80350004	Colorado	Douglas	70.94	70.23	71.55	70.83
80590006	Colorado	Jefferson	72.09	71.42	72.69	72.02
80590011	Colorado	Jefferson	72.97	72.32	73.68	73.02
90010017	Connecticut	Fairfield	71.60	71.52	72.30	72.22
90013007	Connecticut	Fairfield	73.09	72.84	73.99	73.74
90019003	Connecticut	Fairfield	74.83	74.63	75.03	74.83
90099002	Connecticut	New Haven	70.77	70.51	72.78	72.51
170310001	Illinois	Cook	69.05	68.96	72.87	72.77
170310032	Illinois	Cook	69.37	69.32	71.98	71.93
170310076	Illinois	Cook	68.75	68.71	71.56	71.52
170314201	Illinois	Cook	69.10	69.02	72.61	72.53
170317002	Illinois	Cook	69.36	69.18	72.27	72.09
480391004	Texas	Brazoria	70.93	69.35	73.09	71.46
482010024	Texas	Harris	76.28	74.77	77.82	76.28
490110004	Utah	Davis	72.20	71.61	74.42	73.81
490353006	Utah	Salt Lake	73.00	72.40	74.61	74.00
490353013	Utah	Salt Lake	74.10	73.45	74.60	73.95
490570002	Utah	Weber	70.30	69.74	72.22	71.64
550590019	Wisconsin	Kenosha	72.01	71.80	72.91	72.70
550590025	Wisconsin	Kenosha	68.46	68.19	71.48	71.19
551010020	Wisconsin	Racine	70.52	70.33	72.42	72.24
Average AQ Change Relative to Base (ppb)						0.43
Total PPB Change Across All Receptors Relative to Base (ppb)						9.42

Figures 1 and 2 to Section VI.D.1, included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD available in the docket for this rulemaking, illustrate the air quality improvement relative to the estimated representative cost associated with the previously identified emissions control technologies. The graphs show improving air quality at the downwind receptors as emissions reductions commensurate with the identified control technologies are assumed to be implemented. Figure 1 to Section VI.D.1 [191] reflects emissions reductions commensurate with optimization of existing SNCRs and SCRs. Figure 2 to Section VI.D.1 [192] reflects emissions reductions commensurate with installation of new post combustion controls (mainly SCRs) layered on top of the emissions reduction potential from the technologies represented in Figure 1 to Section VI.D.1.[193] The graphic, and underlying AQAT receptor-by-receptor analysis demonstrates that air quality continues to improve at downwind receptors as EPA examines increasingly stringent EGU NO_X control

[191] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[192] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[193] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

technologies. While all major technology breakpoints identified in Sections VI.B and VI.C of this proposed rule show continued air quality improvements at problematic receptors and at cost and technology choice levels that are commensurate with mitigation strategies that are proven to be widely available and implemented, EPA's quantification and application of those breakpoints reflect certain exclusions to: (1) Preserve this consistency with widely observed mitigation measures in states, and (2) remove any retrofit assumptions at marginal units that would have much higher dollar per ton representative cost and little or no air quality benefit. For instance, the EPA does not define the SCR retrofit breakpoint ($11,000 per ton) to include retrofit application at steam units less than 100 MW or at oil/gas steam units emitting at less than 150 tons per ozone season. The emissions reductions from these potential categories of measures are small and do not constitute additional ''breakpoints'' in EPA's estimation. They would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. This careful calibration of technology breakpoints through exclusion of measures that are clearly not cost-effective in terms of air quality benefit allows for the identification of an EGU strategy that is an appropriate reflection of those readily available and widely implemented emissions reduction strategies that will have meaningful downwind air quality impact.

Moreover, these technologies (and representative cost) are demonstrated ozone pollution mitigation strategies that are widely practiced across the EGU fleet and are of comparable stringency to emissions reduction measures that many downwind states have already instituted. The coal SCR retrofit measures driving the majority of the emissions reductions in this action not only reflect industry best practice, but they also reflect prevailing practice among EGUs. More than 60% of the existing coal capacity already has this technology in place. For nearly 25 years, all new coal-fired EGUs that commenced construction have had SCR (or equivalent emissions rates). The 1997 proposed amendments to subpart Da revised the NO_X standard based on the use of SCR. The NO_X SIP Call (promulgated in 1998) established emissions reduction requirements premised on extensive SCR installation (142 units) and incentivized well over 40 GWs of SCR retrofit in the ensuing years.[194] Similarly, the Clean Air Interstate Rule established emissions reductions requirements in 2006 that assumed another 58 units (15 GW) would be installed in the ensuing years among just 10 states, and an even greater volume of capacity chose SCR retrofit measures in the wake of finalizing that action.[195]

Basing emission reduction requirements for EGUs on SCR retrofits is also consistent with regulatory approaches adopted by states, which—particularly in downwind areas more impacted by ozone transport contribution from upwind state emissions—have already adopted SCR-based standards as part of stringent NO_X control programs. Regulatory programs that impose stringent Reasonably Available Control Technology (RACT) requirements on all major power plants and Lowest Achievable Emission Rate (LAER) standards on all new major sources of NO_X have resulted in remaining coal sources in states along the Northeast Corridor such as Connecticut, Delaware, New Jersey, New York, and Massachusetts all being retrofitted with SCR.[196] The Maryland Code of Regulations requires coal fired sources to operate existing SCR controls or install SCR controls by specified dates.[197] Programs like North Carolina's Clean Smokestacks Act and Colorado's Clean Air, Clean Jobs Act have also required or prompted SCR retrofits on units.[198] Unit-level Best Available Retrofit Technology (BART) requirements for the first Regional Haze planning period also determined SCR retrofits (and corresponding emissions rates) were cost-effective controls for a variety of sources in the U.S.[199]

As shown in Figure 1 to Section VI.D.1,[200] the majority of EGU emissions reduction potential and associated air quality improvements estimated for 2023 occurs from optimization of existing SCRs, with some additional reductions from installation of state-of-the-art combustion controls at the same representative cost threshold. At the slightly higher representative cost threshold of $1,800 per ton, there is some additional air quality improvement from optimization of existing SNCRs. These measures taken together represent the control stringency at which near-term incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the near-term emissions control technologies are available at reasonable cost and that these reductions provide meaningful improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors. Figure 1 to Section VI.D.1[201] highlights (1) the continuous connection between identified emission reduction potential and downwind air quality improvement across the range of near-term mitigation measures assessed, and (2) the cost-effective availability of these reductions and corresponding air quality improvements.

Additional considerations that are unique to EGUs provide additional support for EPA's proposal to include SCR and SNCR optimization as part of the identified near-term control stringency, including:

- These controls are already installed and available for operation on these units;
- they are on average already partially operating, but not necessarily optimized;
- the reductions are available in the near-term (during ozone seasons when the problematic receptors are projected to persist), including by the 2023 ozone season aligned with the Moderate area attainment date; and
- these sources are already covered under the existing CSAPR NO_X Ozone Season Group 2 or Group 3 Trading Programs or the Acid Rain Program and thus have the monitoring, reporting, recordkeeping, and all other necessary elements of compliance with the trading program already in place.

The majority of emissions reduction potential and associated air quality improvements estimated for 2026 occur from retrofitting uncontrolled steam sources with post-combustion controls. At the representative cost threshold of $11,000 per ton, there are significant additional air quality improvements from emissions reductions commensurate with installation of new SCRs and SNCRs. These measures taken together with the near-term emissions reduction measures described

[194] 63 FR 57448.

[195] 71 FR 25345.

[196] EPA–HQ–OAR–2020–0272. Comment letter from Attorneys General of NY, NJ, CT, DE, MA.

[197] COMAR 26.11.38 (control of NO_X Emissions from Coal-Fired Electric Generating Units).

[198] *https://www.epa.gov/system/files/documents/2021-09/table-3-30-state-power-sector-regulations-included-in-epa-platform-v6-summer-2021-refe.pdf.*

[199] *See* table 3–35 BART regulations in EPA IPM documentation available at *https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6-summer-2021-reference-case.*

[200] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[201] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

previously represent the level of control stringency in 2026 at which incremental EGU NO_X reduction potential and corresponding downwind ozone air quality improvements are maximized. This evaluation shows that EGU NO_X reductions for each of the emissions control technologies are available at reasonable cost and that these reductions can provide improvements in downwind ozone concentrations at the identified nonattainment and maintenance receptors.

The EPA finds that the control stringency that reflects optimization of existing SCRs and SNCRs, installation of state-of-the-art combustion controls, and the retrofitting of new post combustion controls at the coal and oil/gas steam capacity described previously results in nearly 90,000 tons of NO_X reduction (approximately 43 percent of the 2026 baseline level) for the 22 linked states in 2026 subject to a FIP for EGUs, which will deliver notable air quality improvements across all transport-impacted receptors and assist in fully resolving one downwind air quality problem for the 2015 ozone NAAQS. Figure 2 to Section VI.D.1 [202] demonstrates the continuous connection between identified emissions reduction potential and downwind air quality improvement across the range of mitigation measures assessed in 2026. At no point do the additional emission mitigation measures examined here fail to produce corresponding downwind air quality improvements.

The EPA is proposing that emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades constitute the Agency's selected control stringency for EGUs for those states linked to downwind nonattainment or maintenance in 2023. For those states also linked in 2026, the EPA is determining that the appropriate EGU control stringency also includes emissions reductions commensurate with the retrofit of SCR at coal steam units of 100 MW or greater capacity (excepting circulating fluidized bed units), new SNCR on coal steam units of less than 100 MW capacity and circulating fluidized bed units, and SCR on oil/gas steam units greater than 100 MW that have historically emitted at least 150 tons of NO_X per ozone season.

As noted previously in Section VI.B of this proposed rule and in the EGU NO_X Mitigation Strategies Proposed Rule TSD, the EPA considered other methods of identifying mitigation measures (*e.g.,* SCRs on smaller units, combustion control upgrades on combustion turbines, SCRs on combustion turbines). The emission reductions from these potential categories of measures do not constitute additional ''technology breakpoints'' in EPA's estimation, but rather reflect a different tier of assessment where further mitigation measures are based on inclusion of smaller and/or different generator type of unit (rather than pollution control technology). Emissions reductions from these measures are relatively small and would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. Although these additional measures are not included in EPA's technology breakpoint analysis discussed above, the EPA did examine the cost, potential reductions, and air quality impact of these additional measures in a supplemental analysis to affirm that they do not merit inclusion in the proposed stringency for this action. Similar to prior rules, there is a notable ''knee-in-the-curve'' breakpoint if these additional measures are included in EPA's analysis. In other words, there are very little additional emissions reductions and air quality improvement at problematic receptors, and the cost associated with these measures increases substantially on a dollar per ton basis. The graphic below illustrates the significant loss in cost-effectiveness of reductions if these measures had been included in EPA's proposed stringency.[203]

This proposed determination regarding the appropriate level of control stringency for EGUs to eliminate significant contribution from upwind states finds that the amounts of NO_X emissions reduction achieved through these strategies at EGUs are necessary and cost-justified under the Step 3 multifactor analysis for as long as the strategies remain available to the sources. In other words, the EPA finds at Step 3 that so long as the identified NO_X emissions reduction controls are available and can be implemented (such as optimization of SCRs), they must be implemented, even as total NO_X emissions reductions on a mass basis decline. EPA's Step 3 finding is *not* limited to a determination of the mass-based reduction in emissions that the EPA determines is achievable for the covered EGU fleet under current operating conditions. Rather, the EPA finds at Step 3 that EGUs must continue to achieve NO_X emissions performance in the ozone season commensurate with the level of emissions control stringency the EPA determines appropriate under the multifactor test as set forth in this section. The stringency of the emissions budgets would simply reflect the stringency of the emissions control strategies and would do so more consistently over time than EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking. This retention of a constant degree of stringency over time in emissions budgets under a flexible trading program would not constitute over-control any more than the permanent imposition of emissions rate standards on individual sources at the time of the rulemaking would constitute over-control.

EPA acknowledges that this is an adjustment in its historical approach to eliminating significant contribution, although it is consistent with the evolution of the Agency's thinking as set forth in the Revised CSAPR Update. In CSAPR and the CSAPR Update, EPA established static budgets at Step 4 based on the selected level of control stringency at Step 3. EPA's experience with this approach has been that while the initial mass-based budgets are achieved and compliance targets are even exceeded, this leads to a loss in efficacy of the program as the incentive to reduce emissions declines over time. Some sources emit at higher levels or relax their operation of NO_X controls in response to the build-up of allowances available for compliance, even though EPA has concluded those controls are necessary to meet the statutory good neighbor requirements. This result is inconsistent with the statutory mandate to ''prohibit'' significant contribution and interference with maintenance of the NAAQS in other states, as evidenced most clearly in CAA section 126, which makes it unlawful for a source ''to *operate* more than three months after [a finding that the source emits or would emit in violation of the good neighbor provision] has been made with respect

[202] Included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD, which is available in the docket for this rulemaking.

[203] This is not to discount the potential effectiveness of these or other NO_X mitigation strategies outside the context of this rulemaking to address regional ozone transport on a nationwide basis. States and local jurisdictions may find such measures particularly impactful or necessary in the context of local attainment planning or other unique circumstances. Further, while the EPA proposes this rule as a complete remedy to the problem of interstate transport for the 2015 ozone NAAQS, the EPA has in the past recognized that circumstances may arise after the promulgation of remedies under CAA section 110(a)(2)(D)(i)(I) in which the exercise of further remedial authority against specific stationary sources or groups of sources under CAA section 126 may be warranted. *See* Response to Clean Air Act Section 126(b) Petition From Delaware and Maryland, 83 FR 50444, 50453–54 (Oct. 5, 2018).

to it.'' 42 U.S.C. 7426(c)(2) (emphasis added). Moreover, there is no policy justification at Step 3 for an upwind source to relax or cease operating its emissions controls simply because other sources of pollution have been reduced. In the Revised CSAPR Update, the EPA began to address this problem by establishing adjusted emissions budgets for each year from 2021 through 2025 based on information about the changing EGU fleet known at the time of promulgation of the rule. *See* 86 FR 23118. As discussed in Section VII.B of this proposed rule, the EPA is now implementing a more complete approach to eliminating significant contribution by imposing dynamic budget updates and banking restrictions to ensure that its selected control stringency at Step 3 continues to be implemented.

This approach at Step 4 is wholly consistent with EPA's findings at Step 3. This is best illustrated by comparing the trading program approach with the requirements the EPA could promulgate for EGUs based on an approach of assigning unit-specific emissions rate limitations. Under the latter approach, the EPA would assign an enforceable emissions rate to each EGU, based on the operation of the selected NO_X control strategy (*e.g.,* optimizing existing SCRs) that would apply in perpetuity. By continually adjusting budgets to ensure that emissions outcomes are achieved—and downwind air quality benefits are delivered—that are commensurate with the continuous operation of emissions controls at the selected control stringency at Step 3, the EPA is better aligning the implementation of the program at Step 4 with the level of emissions reductions from upwind sources that the EPA has determined is appropriate through the Step 3 multifactor analysis.[204] The EPA requests comment on its identified EGU control stringencies, including its consideration of the cost, air quality impacts, and timing of such mitigation strategies.

2. Non-EGU Assessment

The Agency prepared the non-EGU screening assessment for 2026 using the analytical framework detailed in Section VI.B.2 of this proposed rule. Using a $7,500/ton (in 2016 dollars) marginal cost threshold identified in the framework, the screening assessment used CoST with known controls, the CMDB, and the 2019 emissions inventory and estimated emissions reductions from emissions units in the Tier 1 industries and impactful boilers in the Tier 2 industries.

Using 2026 as the potential earliest date by which controls on emissions units in the Tier 1 industries and impactful boilers in the Tier 2 industries could be installed, the EPA assessed whether these emissions reduction controls should be required at Step 3 under its multi-factor test.

The EPA determined that, for 2026, the average air quality improvement at receptors relative to the EGU case when SCR post-combustion controls were installed was 0.18 ppb when Tier 1 non-EGU controls were applied and an additional 0.04 ppb when Tier 2 non-EGU controls were applied, based on the Step 3 analysis. The EPA determined for the purposes of Step 3 that all but 3 receptors remain nonattainment or maintenance after the application of these controls, with two receptors (one in Brazoria County, Texas and one in Kenosha County, Wisconsin) switching from maintenance to attainment with these non-EGU controls in place.

TABLE VI.D.2–2—AIR QUALITY AT RECEPTORS IN 2026 FROM NON-EGU INDUSTRIES

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2
40278011	Arizona	Yuma	70.11	70.06	71.81	71.76
80350004	Colorado	Douglas	70.94	70.07	71.55	70.67
80590006	Colorado	Jefferson	72.09	71.26	72.69	71.86
80590011	Colorado	Jefferson	72.97	72.16	73.68	72.86
90010017	Connecticut	Fairfield	71.60	71.35	72.30	72.04
90013007	Connecticut	Fairfield	73.09	72.54	73.99	73.43
90019003	Connecticut	Fairfield	74.83	74.40	75.03	74.59
90099002	Connecticut	New Haven	70.77	70.22	72.78	72.21
170310001	Illinois	Cook	69.05	68.73	72.87	72.53
170310032	Illinois	Cook	69.37	69.20	71.98	71.80
170310076	Illinois	Cook	68.75	68.51	71.56	71.31
170314201	Illinois	Cook	69.10	68.83	72.61	72.32
170317002	Illinois	Cook	69.36	68.98	72.27	71.88
480391004	Texas	Brazoria	70.93	68.72	73.09	70.81
482010024	Texas	Harris	76.28	74.23	77.82	75.73
490110004	Utah	Davis	72.20	71.51	74.42	73.70
490353006	Utah	Salt Lake	73.00	72.30	74.61	73.90
490353013	Utah	Salt Lake	74.10	73.34	74.60	73.84
490570002	Utah	Weber	70.30	69.63	72.22	71.53
550590019	Wisconsin	Kenosha	72.01	71.57	72.91	72.47
550590025	Wisconsin	Kenosha	68.46	67.95	71.48	70.95
551010020	Wisconsin	Racine	70.52	70.12	72.42	72.02
Average AQ Change Relative to Base (ppb)						0.64

[204] The EPA does not believe this adjustment in its Step 3 approach for EGUs, or its corresponding, improved approach to the trading program at Step 4—which, again, mimics the effect of permanent and enforceable unit-specific emissions limits—violates the prohibition on over-control. Our over-control analysis is set forth below in Section VI.D of this proposed rule, and the EPA proposes to find that there is no over-control at the proposed stringency (for both EGUs and non-EGUs) in any upwind state.

TABLE VI.D.2–2—AIR QUALITY AT RECEPTORS IN 2026 FROM NON-EGU INDUSTRIES—Continued

Monitor ID No.	State	County	Average DV (ppb)		Max DV (ppb)	
			Baseline (engineering analysis)	EGU SCR/ SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2	Baseline (engineering analysis)	EGU SCR/SNCR optimization + LNB upgrade + SCR/SNCR retrofit + non-EGU Tier 1 + Tier 2
Total PPB Change Across All Receptors Relative to Base (ppb)						14.13

For more information about how this assessment was performed and the results of the analysis for each receptor, refer to the Ozone Transport Policy Analysis Proposed Rule TSD and to the Ozone AQAT included in the docket for this rule.

a. Request for Comment on Non-EGU Control Strategies and Measures

In the non-EGU screening assessment, the EPA used CoST, the CMDB, and the 2019 emissions inventory to assess emissions reduction potential from non-EGU emissions units in several industries. The EPA identified emissions units that were uncontrolled or that could be better controlled and then applied control technologies to estimate emissions reductions and costs. As noted previously, the cost estimates do not include monitoring, recordkeeping, reporting, or testing costs. Based on the available information, the EPA is proposing to require implementation of the non-EGU emissions reductions at Step 3 by the beginning of the 2026 ozone season. The EPA discusses the basis for this proposed compliance schedule in Section VII.A.2 of this proposed rule.

The EPA requests comment on certain estimates and assumptions in this proposal that may affect EPA's evaluation of the capital and annual costs of several potential control technologies. In particular, the EPA requests comment on whether ultra-low NO_X burners or low NO_X burners are generally considered part of the process or add-on controls for ICI boilers (and how process changes or retrofits to accommodate controls would affect the cost estimates). We request comment on our estimates regarding the effectiveness of low emissions combustion in controlling NO_X from RICE compared to other potential NO_X controls for these engines. We request comment on whether controls on ICI boilers and reciprocating IC engines are likely to be run all year (*e.g.,* 8,760 hours/year) or only during the ozone season.

The EPA notes that the non-EGU NO_X mitigation strategy in this proposed rule focuses on obtaining emissions reductions from non-EGU units that were quantitatively determined to have the most significant impacts on air quality improvements at the downwind nonattainment and maintenance receptors. However, the EPA requests comment on the merits of requiring non-EGU sources within the linked upwind states to meet specified technology-based control standards, such as the RACT SIP requirements outlined in CFR part 51 for non-EGU sources located in OTR states.

3. Combined EGU and Non-EGU Assessment

The EPA used the Ozone AQAT to evaluate the combined impact of these selected stringency levels for both EGUs and non-EGUs on all receptors remaining in the 2026 air quality modeling base case to inform the over-control analysis. EPA's evaluation demonstrated air quality improvement at the 22 remaining nonattainment or maintenance receptors outside of California (*see* Section V.D of this proposed rule for receptor details). The EPA estimated that the average air quality improvement at these receptors relative to the engineering analytics base case was 0.64 ppb for emissions reductions commensurate with optimization of existing SCRs/SNCRs, combustion control upgrades, application of new post-combustion control (SCR and SNCR) retrofits at eligible units, and all estimated emissions reductions from the Tier 1 industries and impactful boilers in the Tier 2 industries. Table VI.D.1–3 summarizes the results of EPA's Step 3 evaluation of air quality improvements at these receptors using AQAT. In summary, the collective application of these mitigation measures and emissions reductions continue to deliver downwind air quality improvements up until the most stringent thresholds identified. The health and climate benefits resulting from application of these measures (as described in the RIA) are estimated to exceed the costs, and the identified technologies reflect not only demonstrated best practices—but widely adopted best practices in the case of EGU retrofits.

TABLE VI.D.3–1—CHANGE IN AIR QUALITY REDUCTIONS AT RECEPTORS IN 2026 FROM PROPOSED EGU AND NON-EGU EMISSIONS REDUCTIONS [a b c]

Tier/technology	Ozone season emissions reductions	Total PPB change across all downwind receptors [d]	Average PPB change across all downwind receptors
EGU (SCR/SNCR optimization + LNB upgrade) + Gen shifting	26,250	1.53	0.07
EGU SCR/SNCR Retrofit + Gen shifting	63,883	7.89	0.36
Non-EGU (Tier 1)	41,153	3.89	0.18
Non-EGU (Tier 2)	6,033	0.82	0.04
Total		14.13	0.64

Table Notes:

[a] As in prior rules, for the purpose of defining significant contribution at Step 3, the EPA evaluated air quality changes resulting from the application of the emissions reductions in only those states that are linked to each receptor as well as the state containing the receptor. By applying reductions to the state containing the receptor, the EPA ensures that it is accounting for the downwind state's fair share. In addition, this method holds each upwind state responsible for its fair share of the downwind problems to which it is linked. Reductions made by other states in order to address air quality problems at other receptors do not increase or decrease this share. The air quality impacts on design values that reflect the emissions reductions in all linked states and the health and climate benefits from this proposal are discussed in Section IX of this proposed rule.

[b] The EPA notes that the design values reflected in Tables VI.D.1–1 and 2 correspond to the engineering analysis EGU emissions inventory used in AQAT to determine state-level baseline emissions and reductions at Step 3. These tools are discussed in greater detail in the Ozone Transport Policy Analysis Proposed Rule TSD. Additionally, these emission reduction values vary slightly from the technology reduction estimates described in Section VI.C, as the values here reflect (1) the sum of the final identified stringency for each state (*e.g.,* SCR retrofit potential is not assumed in Alabama, Delaware, and Tennessee), and (2) generation shifting reduction potential identified at each step.

[c] The total and average ppb results from non-EGUs emissions reductions shown here were generated using the Step 3 AQAT methodology consistent with that for EGUs (*i.e.,* including reductions from the state containing the receptor and excluding states that are not explicitly linked to particular receptors). The values shown in Table VI.C.2–1 were prepared for the non-EGU screening assessment using a methodology where states within the program make emissions reductions for all receptors. States that contain receptors (*i.e.,* Connecticut and Colorado) that are not linked to other receptors are not assumed to make reductions under that methodology.

[d] The cumulative ppb change only shows the aggregate change across all problematic receptors (some of which are located within close proximity to one another) in this part of the Step 3 analysis. Section IX of this proposed rule provides a more complete picture of the air quality impacts of the proposed rule.

4. Over-Control Analysis

The EPA applied its over-control test to this same set of aggregated EGU and non-EGU data described in the previous section. As part of the air quality analysis using the Ozone AQAT, the EPA evaluated potential over-control with respect to whether (1) the expected ozone improvements would be greater than necessary to resolve the downwind ozone pollution problem (*i.e.,* beyond what is necessary to resolve all nonattainment and maintenance problems to which an upwind state is linked) or (2) the expected ozone improvements would reduce the upwind state's ozone contributions below the screening threshold (*i.e.,* 1 percent of the 2015 ozone NAAQS).

In *EME Homer City,* the Supreme Court held that the EPA cannot ''require[ ] an upwind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked.'' 572 U.S. at 521. On remand from the Supreme Court, the D.C. Circuit held that this means that the EPA might overstep its authority ''when those downwind locations would achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations.'' *EME Homer City II,* 795 F.3d at 127. The D.C. Circuit qualified this statement by noting that this ''does not mean that every such upwind state would then be entitled to less stringent emissions limits. Some of those upwind States may still be subject to the more stringent emissions limits so as not to cause other downwind locations to which those States are linked to fall into nonattainment.'' *Id.* at 14–15. As the Supreme Court explained, ''while EPA has a statutory duty to avoid over-control, the Agency also has a statutory obligation to avoid 'under-control,' *i.e.,* to maximize achievement of attainment downwind.'' 572 U.S. at 523. The Court noted that ''a degree of imprecision is inevitable in tackling the problem of interstate air pollution'' and that incidental over-control may be unavoidable. *Id.* ''Required to balance the possibilities of under-control and over-control, EPA must have leeway in fulfilling its statutory mandate.'' *Id.*[205]

Consistent with these instructions from the Supreme Court and the D.C. Circuit, using the Ozone AQAT, the EPA first evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions selected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems (see the Ozone Policy Analysis Proposed Rule TSD for details on the construction and application of AQAT). The control stringency selected for 2023 (a representative cost threshold of $1,800 per ton for EGUs) includes emissions reductions commensurate with optimization of existing SCRs and SNCRs and installation of state-of-the-art combustion controls, which are estimated to change the status of one maintenance receptor, shifting the Clark County, Nevada monitor to attainment in 2023. However, no other nonattainment or maintenance problems would be resolved in 2023 with this level of stringency, and no state is linked solely to this receptor. Nor do any states' contribution levels drop below the 1% of NAAQS threshold. Thus, the EPA determined that none of the 26 linked states have all of their linkages resolved at the proposed EGU level of control stringency in 2023, and hence, the EPA finds no over-control in the proposed level of stringency.

Based on the air quality baseline modeling for 2026, all receptors to which Alabama, Delaware, and Tennessee are linked in 2023 are projected to be in attainment in 2026. Therefore, no additional emissions reductions are proposed for EGUs or non-EGUs in those states beyond the 2023 level of stringency. For the remaining 23 states, the selected control stringency (at a representative cost per ton threshold of $11,000 for EGUs and a marginal cost threshold of $7,500 for non-EGUs) beginning in 2026 includes additional EGU controls and estimated non-EGU emissions reductions for Tier 1 and Tier 2 non-EGU industries. The EPA used the Ozone AQAT to evaluate the impact of this selected stringency level (as well as other potential stringency levels) on all receptors remaining in the 2026 air quality modeling base case. This assessment shows that the selected control stringency level and emissions reductions are estimated to change the status of three maintenance receptors to attainment in 2026—Douglas County, Colorado; Brazoria County, Texas; and Kenosha County, Wisconsin. Based on these data, EPA proposes that at least 20 of the 23 states continue to be linked to nonattainment or maintenance receptors after implementation of all identified Step 3 reductions, and hence, the EPA finds no over-control in its determination of that level of stringency for those 20 states.

For 2 of the 23 states, Arkansas and Mississippi, the last downwind receptor to which these two states are linked (*i.e.,* Brazoria County, Texas) is estimated to achieve attainment and maintenance after full application of EGU reductions and Tier 1 non-EGU reductions. This suggests application of the estimated non-EGU emissions reductions from Tier 2 *may* constitute over-control for these states. However, this downwind

[205] Although the Court described over-control as going beyond what is needed to address ''nonattainment'' problems, the EPA interprets this holding as not impacting its approach to defining and addressing both nonattainment and maintenance receptors. In particular, the EPA continues to interpret the Good Neighbor provision as requiring it to give independent effect to the ''interfere with maintenance'' prong. *Accord Wisconsin,* 938 F.3d at 325–27.

receptor only resolves by a small margin after the application of all EGU and Tier 1 non-EGU emissions reductions. The EPA anticipates that updates to emissions inventories, emissions reduction potential from identified technologies, or the over-control test methodology resulting from comments or other updated information could possibly move this site back into nonattainment- or maintenance-receptor status when the EPA conducts an over-control analysis prior to finalizing this proposal.

For 1 of the 23 states, Wyoming, the EPA also notes a potential over-control finding under the methodological assumption where emissions reductions of commensurate stringency are assumed in the downwind state of Colorado (which is not subject to this proposal). As demonstrated in the Ozone Transport Policy Analysis Proposed Rule TSD, the last downwind receptor for Wyoming (*i.e.,* Douglas County, Colorado) is estimated to achieve attainment and maintenance after full application of EGU reductions. This suggests application of estimated non-EGU emissions reductions from Tier 1 and Tier 2 industries may constitute over-control for this state. However, when the assumption of commensurate downwind state reductions in Colorado is removed from the methodology, the downwind receptor to which Wyoming is linked does not resolve and there is no identified over-control estimated for Wyoming.[206]

Next, the EPA evaluated the potential for over-control with respect to the 1 percent of the NAAQS threshold applied in this proposed rulemaking at Step 3 of the good neighbor framework, assessed for the selected control stringencies for each state for each period that downwind nonattainment and maintenance problems persist (*i.e.,* 2023 and 2026). Specifically, the EPA evaluated whether the selected control stringencies would reduce upwind emissions to a level where the contribution from any of the 26 linked states in 2023 or 23 linked states in 2026 would be below the 1 percent threshold. The EPA finds that for the mitigation measures assumed in 2023 and in 2026, all states that contributed greater than or equal to the 1 percent threshold in the base case continued to contribute greater than or equal to 1 percent of the NAAQS to at least one remaining downwind nonattainment or maintenance receptor for as long as that receptor remained in nonattainment or maintenance. In the case of Arkansas, Mississippi, and Wyoming, while their linkages resolved based on a change in receptor status at Step 1 (as discussed above), their contribution to the relevant monitoring sites remained above 1 percent of the NAAQS, and thus, the potential basis for an over-control finding with respect to these states is not based on their contribution dropping below 1 percent of the NAAQS at those sites. For more information about this assessment, refer to the Ozone Transport Policy Analysis Proposed Rule TSD and the Ozone AQAT.

Based on these results, under no scenario does EPA's AQAT analysis for this proposal indicate that including all identified EGU reductions would constitute over-control. Rather, if these results hold for a final rule, the potential over-control for Arkansas and Mississippi can be avoided by not requiring Tier 2 non-EGU reductions, and over-control for Wyoming can be avoided by not requiring any non-EGU reductions.

Nonetheless, while acknowledging these preliminary analytic results, the EPA is proposing that all of the selected EGU and non-EGU NO_X reduction strategies selected in EPA's Step 3 analysis be applied to all linked states in 2026—including to Arkansas, Mississippi, and Wyoming—to eliminate significant contribution to nonattainment and interference with maintenance of the 2015 ozone NAAQS. The Supreme Court has directed the EPA to avoid both over-control and under-control in addressing good neighbor obligations. In addition, the D.C. Circuit has reinforced that over-control must be established based on particularized, record evidence on an as-applied basis. As noted previously, even slight changes in analytics based on comments or new information between proposal and final could result in the Brazoria, Texas site remaining either a nonattainment or maintenance receptor. Further, with respect to Wyoming, its linkage only resolves based on an unenforceable assumption regarding a certain level of emissions reduction in Colorado. The proposed determination that the stringency of this proposal does not constitute over-control for any linked state is further reinforced by EPA's observation in Section IV.A.1 of this proposed rule regarding the nature of ozone, and in particular, that future ozone concentrations and the formation of ground level ozone, may be impacted by climate change in future years.

Under these circumstances, the EPA cannot conclude based on the current record that any aspect of its selected Step 3 level of control stringency constitutes unnecessary over-control for any of the 23 states found to be linked in 2026. The EPA requests comment on this proposed conclusion. The EPA requests comment on an alternative conclusion that, if this same analysis were to persist for a final rule, it must limit non-EGU reduction requirements for Arkansas and Mississippi to only the Tier 1 industries, and for Wyoming to limit the stringency of the rule to only the EGU reduction strategies.

VII. Implementation of Emissions Reductions

A. NO_X Reduction Implementation Schedule

This proposal, if finalized, will ensure that emissions reductions necessary to eliminate significant contribution will be achieved as ''as expeditiously as practicable'' as required under CAA section 181(a). The EPA's anticipated timing will provide for all possible emissions reductions to go into effect beginning in the 2023 ozone season, which is aligned with the next upcoming attainment date of August 3, 2024, for areas classified as Moderate nonattainment under the 2015 ozone standard. Additional emissions reductions that the EPA finds not possible to implement by that attainment date are proposed to take effect as expeditiously as practicable, with the full suite of emissions reductions taking effect by the 2026 ozone season, which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS. This schedule of emissions reductions meets the requirement in the Good Neighbor Provision that it must be

[206] In this proposal, the EPA continues to assume, as it has in prior transport rules, that home-states (that are not otherwise linked) will make similar reductions as those assumed in this action for purposes of local attainment. While the EPA continues to view this to be an equitable means of assessing air quality improvement from good neighbor actions, because the downwind receptor state is assumed to do its ''fair share,'' the EPA recognizes that recent case law has called the need for such an assumption into question, and thus using this assumption as a basis for finding over-control may be inappropriate. In *Maryland,* the EPA had argued that good neighbor obligations should not be required by the Marginal area attainment deadline in part because ''marginal nonattainment areas often achieve the NAAQS without further downwind reductions, so it would be unreasonable to impose reductions on upwind sources based on the next marginal attainment deadline.'' 958 F.3d 1185, 1204. The D.C. Circuit rejected that argument, noting regulatory consequences for the downwind state for failure to attain even at the Marginal date, and, citing *Wisconsin,* the court held that upwind sources violate the good neighbor provision if they significantly contribute even at the Marginal area attainment date. *Id.* Thus, the EPA examines over-control in this proposal with and without this assumption of home-state emission reductions.

implemented ''consistent with the provisions of [title I of the CAA.]'' CAA section 110(a)(2)(D)(i). Finally, the timing of this proposed rulemaking is designed to achieve reductions as expeditiously as practicable while adhering to the procedural requirements of CAA section 110. The EPA proposes this rule to constitute a full remedy for interstate transport for the 2015 ozone NAAQS for the states covered by this proposal; the EPA does not anticipate further rulemaking to address good neighbor obligations will be required for these states with the finalization of this rule.

EPA's proposed determinations regarding the timing of this proposed rule are informed by and in compliance with several recent court decisions. The D.C. Circuit has reiterated several times since 2008 that, under the terms of the Good Neighbor Provision, upwind states must eliminate their significant contributions to downwind areas ''consistent with the provisions of [title I of the Act],'' including those provisions setting attainment deadlines for downwind areas.[207] In *North Carolina,* the D.C. Circuit found the 2015 compliance deadline that the EPA had established in CAIR unlawful in light of the downwind nonattainment areas' 2010 deadline for attaining the 1997 NAAQS for ozone and $PM_{2.5}$.[208] Similarly, in *Wisconsin,* the Court found the CSAPR Update unlawful to the extent it allowed upwind states to continue their significant contributions to downwind air quality problems beyond the downwind states' statutory deadlines for attaining the 2008 ozone NAAQS.[209] More recently, in *Maryland,* the Court found the EPA's selection of a 2023 analysis year in evaluating state petitions submitted under CAA section 126 unlawful in light of the downwind Marginal nonattainment areas' 2021 deadline for attaining the 2015 ozone NAAQS.[210] The Court noted in *Wisconsin* that the statutory command—that compliance with the Good Neighbor Provision must be achieved in a manner ''consistent with'' title I of the CAA—may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, ''under particular circumstances and upon a sufficient showing of necessity,'' but concluded that ''[a]ny such deviation would need to be rooted in Title I's framework'' and would need to ''provide a sufficient level of protection to downwind States.''[211]

1. 2023–2025: EGU NO_X Reductions Beginning in 2023

The near-term EGU control stringencies and corresponding reductions in this proposed rulemaking cover the 2023, 2024, and 2025 ozone seasons. This is the period in which some reductions will be available, but the large portion of full remedy reductions—mainly those reductions that are driven by post combustion control installation—identified in Sections VI.B through VI.D of this proposed rule are not yet available. The EGU NO_X mitigation strategies available during these initial 3 years are the optimization of existing post-combustion controls (SCRs and SNCRs) and combustion control upgrades. As described in Sections VI.B through VI.D of this proposed rule and in accompanying TSDs, these mitigation measures can be implemented in under two months in the case of existing control optimization and in 6 months in the case of combustion control upgrades.

As described in Section VI.B of this proposed rule and in the identified TSDs, these timing assumptions account for planning, procurement, and any physical or structural modification necessary. The EPA provides significant historical data, including the implementation of the most recent Revised CSAPR Update, as well as engineering studies and input factor analysis documenting the feasibility of these timing assumptions. However, these timing assumptions are representative of fleet averages, and the EPA has noted that some units will likely overperform their installation timing assumptions, while others may have unit configuration or operational considerations that result in their underperforming these timing assumptions. As in prior interstate transport rules, the EPA is implementing these EGU reductions through a trading program approach. The trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions.

However, starting in 2024, as described in Section VII.B.7 of this proposed rule, unit-specific daily emissions rate limits are applied to coal units with existing SCR at a level consistent with operating that control. The EPA believes that implementing these emissions reductions at the state level starting in 2023 (through state emissions budgets) while imposing the unit-specific emissions rate limits in 2024 achieves the necessary environmental performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding daily operation of optimized SCRs.

Additionally, as in prior rules, the EPA assumes combustion control upgrade implementation may take up to 6 months. In the Revised CSAPR Update, covering 12 of the 25 states for which emissions reduction requirements for EGUs are established under this proposed action, the EPA finalized the rule in March of 2021 and thus did not require these combustion control-based emissions reductions in ozone-season state emissions budgets until 2022 (year two of that program).[212] The EPA is applying the same timing assumption regarding combustion control upgrades for this proposed rulemaking given the expected similar window between an anticipated final action date and the start of the year one ozone season. The EPA is not assuming the implementation of any additional combustion control upgrades in state emissions budgets until 2024. Therefore, those 13 states covered in this action for EGU emissions reductions that were not covered in the Revised CSAPR Rule have 2023 emissions budgets that only reflect optimization of existing controls. Any identified combustion control upgrade emissions reductions are reflected beginning in the 2024 ozone-season budgets for these states. For the 12 states covered under the Revised CSAPR Update, any identified emissions reduction potential from combustion control upgrade was included and reflected in those state budgets beginning in 2022 under the Revised CSAPR Update. Therefore, the

[207] *North Carolina* v. *EPA,* 531 F.3d 896 (D.C. Cir. 2008), *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019), and *Maryland* v. *EPA,* 958 F.3d 1185 (D.C. Cir. 2020).

[208] *North Carolina,* 531 F.3d at 911–913.

[209] *Wisconsin,* 938 F. 3d at 303, 3018–20.

[210] *Maryland,* 958 F.3d at 1203–1204. Similarly, in *New York* v. *EPA,* 964 F.3d 1214 (D.C. Cir. 2020), the Court found the EPA's selection of a 2023 analysis year in evaluating New York's section 126 petition unlawful in light of the New York Metropolitan Area's 2021 Serious area deadline for attaining the 2008 ozone NAAQS. 964 F.3d at 1226 (citing *Wisconsin* and *Maryland*).

[211] *Wisconsin,* 938 F. 3d at 320 (citing CAA section 181(a) (allowing one-year extension of attainment deadlines in particular circumstances) and *North Carolina,* 531 F.3d at 912).

[212] 86 FR 23093.

EPA is assuming that this combustion control upgrade potential is available, if not already realized, by the first year of this action (*i.e.,* 2023) in this proposed rule.

2. 2026 and Later Years: EGU and Non-EGU NO_X Reductions Beginning in 2026

In accordance with the good neighbor provision and the downwind attainment schedule under CAA section 181 for the 2015 ozone NAAQS, the EPA is proposing to align its analysis and implementation of the emissions reductions addressing significant contribution from EGU and non-EGU sources that require relatively longer lead time at a sectoral scale with the 2026 ozone season, which is the last full ozone season preceding the August 3, 2027, Serious area attainment date for the 2015 ozone NAAQS.[213] The EPA proposes to find that this compliance deadline is the most expeditious date practicable and would achieve the required emissions reductions prior to the next applicable attainment date by which such reductions are, in fact, possible. The EPA proposes to find that it is not possible to require implementation of all necessary emissions controls across all of the affected EGU and non-EGU sources by the August 3, 2024, Moderate area attainment date.

Thus, the EPA is proposing to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in this section no later than the 2026 ozone season (May through September). If finalized in early 2023, the final rule would provide more than three years for EGU and non-EGU sources to install whatever controls they deem suitable to comply with required emissions reductions by the 2026 ozone season. In addition, the publication of this proposal provides roughly an additional year of notice to these source owners and operators that they should begin engineering and financial planning now to be prepared to meet this implementation timetable.

The EPA views this timeframe for retrofitting post-combustion NO_X emissions controls and other non-EGU controls to be presumptively reasonable and achievable. A 3-year period for installation of post-combustion control technologies is consistent with the statutory timeframe for implementation of the controls required to address interstate pollution under section 110(a)(2)(D) and 126 of the Act, the statutory timeframes for implementation of RACT in ozone nonattainment areas classified as Moderate or above, and other statutory provisions that establish control requirements for existing stationary sources of pollution.

For example, section 126 of the CAA authorizes a downwind state or tribe to petition the EPA for a finding that emissions from ''any major source or group of stationary sources'' in an upwind state contribute significantly to nonattainment in, or interfere with maintenance by, the downwind state. If the EPA makes a finding that a major source or a group of stationary sources emits or would emit pollutants in violation of the relevant prohibition in CAA section 110(a)(2)(D), the source(s) must shut down within 3 months from the finding unless the EPA directly regulates the source(s) by establishing emissions limitations and a compliance schedule extending no later than three years from the date of the finding, to eliminate the prohibited interstate transport of pollutants as expeditiously as practicable.[214] Thus, in the provision that allows for direct federal regulation of sources violating the good neighbor provision, Congress established 3 years as the maximum amount of time available from a final action to when emissions reductions need to be achieved at the relevant source or group of sources.

Additionally, for ozone nonattainment areas classified as Moderate or higher, the CAA requires states to implement RACT requirements less than three years after the statutory deadline for submitting these measures to the EPA.[215] Specifically, for these areas, CAA sections 182(b)(2) and 182(f) require that states implement RACT for existing VOC and NO_X sources as expeditiously as practicable but no later than May 31, 1995, approximately 30 months after the November 15, 1992, deadline for submitting RACT SIP revisions. For purposes of the 2015 ozone NAAQS, the EPA has interpreted these provisions to require implementation of RACT SIP revisions as expeditiously as practicable but no later than January 1 of the fifth year after the effective date of designation, which is less than 3 years after the deadline for submitting RACT SIP revisions.[216] For areas initially designated nonattainment with a Moderate or higher classification effective August 3, 2018 (83 FR 25776), that implementation deadline falls on January 1, 2023, approximately 29 months after the August 3, 2020 submission deadline.[217] Moderate ozone nonattainment areas must also implement all reasonably available control measures (including RACT) needed for expeditious attainment within three years after the statutory deadline for states to submit these measures to the EPA as part of a Moderate area attainment demonstration.[218]

The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA proposes to include in this proposed rule, as well as the types of emissions control technologies on which the EPA proposes to base the

[213] For each nonattainment area classified under CAA section 181(a) for the 2015 ozone NAAQS, the attainment date is ''as expeditiously as practicable'' but not later than the date provided in table 1 to 40 CFR 51.1303(a). Thus, for areas initially designated nonattainment effective August 3, 2018 (83 FR 25776), the latest permissible attainment dates are: August 3, 2021 (for Marginal areas), August 3, 2024 (for Moderate areas), August 3, 2027 (for Serious areas), and August 3, 2033 (for Severe areas).

[214] CAA 110(a)(2)(D)(i) and 126(c).

[215] *See, e.g.,* 40 CFR 51.1112(a)(3) and 51.1312(a)(3)(i) (requiring implementation of RACT required pursuant to initial nonattainment area designations no later than January 1 of the fifth year after the effective date of designation, which is less than 3 years after the submission deadline under 40 CFR 51.1112(a)(2)) and 51.1312(a)(2)(i), respectively).

[216] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation) and 51.1312(a)(3)(i) (requiring implementation of RACT SIP revisions as expeditiously as practicable, but no later than January 1 of the fifth year after the effective date of designation). For reclassified areas, states must implement RACT SIP revisions as expeditiously as practicable, but no later than the start of the attainment year ozone season associated with the area's new attainment deadline, or January 1 of the third year after the associated SIP revision submittal deadline, whichever is earlier; or the deadline established by the Administrator in the final action issuing the area reclassification. 40 CFR 51.1312(a)(3)(ii); *see* also 83 FR 62989, 63012–63014.

[217] 40 CFR 51.1312(a)(2)(i) (requiring submission of RACT SIP revisions no later than 24 months after the effective date of designation).

[218] *See, e.g.,* 40 CFR 51.1108(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than 3 years after the deadline for submission of reasonably available control measures under 40 CFR 51.1112(c) and 51.1108(a)) and 40 CFR 51.1308(d) (requiring implementation of all control measures (including RACT) needed for expeditious attainment no later than the beginning of the attainment year ozone season, which, for a Moderate nonattainment area, occurs less than three years after the deadline for submission of reasonably available control measures under 40 CFR 51.1312(c) and 51.1308(a)). Because the attainment demonstration for a Moderate nonattainment area (including RACT needed for expeditious attainment) is due three years after the effective date of the area's designation (40 CFR 51.1308(a) and 51.1312(c)), and all Moderate nonattainment areas must attain the NAAQS as expeditiously as practicable but no later than 6 years after the effective date of the area's designation (40 CFR 51.1303(a)), the beginning of the ''attainment year ozone season'' (as defined in 40 CFR 51.1300(g)) for such an area is less than three years after the due date for the attainment demonstration.

emissions limitations that would take effect for the 2026 ozone season, generally are intended to be consistent with the scope and stringency of RACT requirements for existing major sources of NO_X in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.[219] Thus, the timing Congress allotted for sources in downwind states to come into compliance with RACT requirements bears directly on the amount of time that should be allotted here and indicates, as does CAA section 126, that 3 years is an outer limit on the time that should be given sources to come into compliance.

Finally, with respect to emissions standards for hazardous air pollutants, section 112(i)(3) of the CAA requires the EPA to establish compliance dates for each category or subcategory of existing sources subject to an emissions standard that ''provide for compliance as expeditiously as practicable, but in no event later than 3 years after the effective date of such standard,'' with limited exceptions.[220] Here again, where Congress was concerned with addressing emissions of pollutants that impact public health, a 3-year time period was allotted as the time needed for existing sources to come into compliance.

All of these statutory timeframes for implementation of new control requirements on existing stationary sources indicate that Congress considered 3 years to be not only a sufficient amount of time but a maximum amount of time allowable for existing stationary sources to install pollution controls as necessary for expeditious attainment, to eliminate prohibited interstate transport of pollutants, and to protect public health.

Further, the EPA notes that, given the number of years that have passed since EPA's promulgation of the 2015 ozone NAAQS and related nonattainment area designations in 2018, and in light of the *Maryland* court's holding that good neighbor obligations for the 2015 ozone NAAQS should have been implemented by the Marginal area attainment date in 2021,[221] many states are substantially delayed in implementing their good neighbor obligations for these NAAQS, and the sources proposed for NO_X emissions control in this rule have continued to operate for several years without the controls necessary to eliminate their significant contribution to ongoing and persistent ozone nonattainment and maintenance problems in other states. Under these circumstances, we find it more than reasonable to require compliance with the control requirements for all non-EGUs and the EGU reductions related to post-combustion control retrofit identified in Section VI.B.1.b of this proposed rule by the beginning of the 2026 ozone season (*i.e.,* by May 1, 2026). May 1, 2026, is more than 3 years after the date by which the EPA currently anticipates promulgating a final FIP for the covered states, more than three years after the January 1, 2023, deadline for implementation of section 182 RACT SIP provisions in areas classified as Moderate or higher, and almost 8 years after the October 1, 2018, deadline for submission of good neighbor SIPs that prohibit significant contribution to nonattainment or interference with maintenance in downwind states.[222]

As the D.C. Circuit noted in *Wisconsin,* the good neighbor provision requires upwind states to ''eliminate their substantial contributions to downwind nonattainment in concert with the attainment deadlines'' in the downwind states, even where those attainment deadlines occur before EPA's statutory deadline to promulgate a FIP.[223] Referencing the Supreme Court's description of the attainment deadlines as ''the heart'' of the CAA, the *Wisconsin* court noted that some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines may be allowed only ''under particular circumstances and upon a sufficient showing of necessity,'' *e.g.,* when compliance with the statutory mandate amounts to an impossibility.[224]

For the reasons provided below in this section, the EPA is proposing to find that installation of certain EGU controls and all non-EGU controls is not possible by the Moderate area attainment date for the 2015 ozone NAAQS (*i.e.,* August 3, 2024),[225] and that the 2026 ozone season, which corresponds to the August 3, 2027, Serious area attainment date for these NAAQS, is the earliest downwind attainment date by which the required emissions reductions from these strategies are possible.

a. EGU Schedule for 2026 and Later Years

As discussed in Sections VI.B through VI.D of this proposed rule, significant emissions reduction potential exists and is included in EPA's quantification of significant contribution based on the potential to install post-combustion controls (SCR and SNCRs) at EGUs. However, as discussed in detail in those sections, the assumption for installation of this technology on a region-wide scale is 36 months in this proposed rule. This amount of time allows for all necessary procurement, permitting, and installation milestones across multiple units in the covered region. Therefore, the EPA proposes to find that these emissions reductions are not available any earlier than the 2026 compliance period. For each year in 2026 and beyond, state emissions budgets include reductions commensurate with these post-combustion control technologies identified for covered units in Step 3. The EPA notes that similar compliance schedules and post-combustion control retrofit installations have been realized successfully in prior programs allowing similar timeframes. Subsequent to the NO_X SIP Call and the parallel Finding of Significant Contribution and Rulemaking on Section 126 Petitions (which became effective December 28, 1998, and February 17, 2000, respectively [226]), nearly 19 GW of SCR

[219] *See* the Non-EGU Sectors TSD for a discussion of SIP-approved RACT rules in effect in downwind states.

[220] CAA section 112(i)(3)(B) generally authorizes the EPA to grant an extension of up to 1 additional year for an existing source to comply with emissions standards ''if such additional period is necessary for the installation of controls,'' and sections 112(i)(4) through (8) provide for limited extensions granted by the President where certain conditions are met, for existing sources that have installed the best available control technology (BACT) or technology required to meet a lowest achievable emissions rate (LAER), and for new sources for which construction or reconstruction is commenced by certain dates.

[221] 958 F.3d at 1203–1204 (remanding the EPA denial of section 126 petition based on the EPA analysis of downwind air quality in 2023 rather than 2021, the year containing the Marginal area attainment date).

[222] CAA sections 110(a)(1) and 110(a)(2)(D)(i) (requiring states to submit, within 3 years after EPA's promulgation of a new or revised NAAQS, SIP provisions adequate to satisfy the Good Neighbor Provision). As the Supreme Court noted in *EME Homer City I,* ''nothing in the statute places EPA under an obligation to provide specific metrics to States before they undertake to fulfill their good neighbor obligations.'' 572 U.S. 489, 510.

[223] 938 F.3d at 317–318. For example, the court observed that the EPA may shorten the deadline for SIP submissions under CAA section 110(a)(1) and may issue FIPs soon thereafter under CAA section 110(c)(1), to align the upwind states' deadline for satisfying good neighbor obligations with the downwind states' deadline for attaining the NAAQS. *Id.* at 318.

[224] *Id.* at 316 and 319–320 (noting that any such deviation must be ''rooted in Title I's framework'' and ''provide a sufficient level of protection to downwind States'').

[225] Compliance by the August 3, 2021, Marginal area attainment date is also impossible as that date has passed.

[226] *See* 63 FR 57356 (October 27, 1998); 65 FR 2674 (January 18, 2000). The D.C. Circuit stayed the NO_X SIP Call by an order issued May 25, 1999. After upholding the rule in most respects in *Michigan* v. *EPA,* 213 F.3d 663 (D.C. Cir. 2000), the court lifted the stay by an order issued June 22, 2000.

retrofit came online in 2002 and another 42 GW of SCR retrofit came online for steam boilers in 2003, illustrating that a considerable volume of SCR retrofit capacity is possible in a 36 month period.

However, the EPA is not proposing to apply daily emissions rates on coal-fired steam EGUs assumed to retrofit SCR until 2027 (as described in Section VII.B.1.c.i of this proposed rule). The EPA believes that implementing these emissions reductions at the state level starting in 2026 (through state emissions budgets) while imposing the unit-specific emissions rate limits in 2027 achieves the necessary environmental performance as soon as possible while accommodating any heterogeneity in unit-level implementation schedules regarding installation of new SCR.[227]

b. Non-EGU Schedule for 2026 and Later Years

For the suite of non-EGU controls on which the EPA has based its Step 3 findings as described in Section VI of this proposed rule, the EPA proposes to require that these controls be installed and operational by the 2026 ozone season and to find that any earlier date is not possible. The EPA previously examined the time necessary to install the controls identified for several non-EGU industries. Although the information on installation times for most NO_X controls applied to glass and cement manufacturing was uncertain, the EPA identified minimum estimated installation times for a number of other non-EGU source categories that ranged from several weeks to slightly over a year. This included timeframes of 42–51 weeks for SNCR applied to dry cement manufacturing facilities and cement kilns/dryers burning bituminous coal, 28–58 weeks for SCR applied to boilers and process heaters, 28–58 weeks for SCR applied to iron and steel in-process combustion, and 6–8 months for low NO_X burners and flue gas recirculation at iron and steel mills.[228] Taking into account necessary scale-up of construction services for multiple control installations at several emissions units, the time needed to have NO_X monitoring installed and operating, and other necessary steps in the permitting and construction processes (*e.g.,* review of vendor bids), the EPA estimates an additional period of 6 to 18 months may be necessary for existing non-EGU sources to install the necessary controls, depending on the number of control installations at a facility.[229]

Additionally, the EPA previously considered the installation timing needs for NO_X controls (including SCR, SNCR, and combustion controls) at both EGU and non-EGU sources as part of the 1998 NO_X SIP Call.[230] With respect to combustion controls (*e.g.,* low-NO_X burners, overfire air, etc.), the EPA found that sources should be able to complete control technology installations and obtain relevant permits in relatively short timeframes given considerable experience at that time among sources and permitting agencies with the implementation of such controls, the fact that combustion controls are constructed of commonly available materials (steel, piping, etc.) and do not require reagent during operation, and the then availability of many vendors of combustion control technology.[231]

With respect to post-combustion controls (primarily SCR and SNCR), the EPA considered three basic factors in assessing installation timing needs: (1) Availability of materials and labor, (2) the time needed to implement controls at plants with single or multiple retrofit requirements, and (3) the potential for interruptions in power supply resulting from outages needed to complete installations on EGUs.[232] Assuming adequate supplies of both off-the-shelf hardware (such as steel, piping, nozzles, pumps, and related equipment) and the catalyst used in the SCR process, as well as sufficient vendor capacity to supply retrofit SCR catalyst to sources, and taking into account the additional time needed for facility engineering review, developing control technology specifications, awarding a procurement contract, obtaining a construction permit, completing control technology design, installation, and testing, and obtaining an operating permit, the EPA found that (a) about 21 months would be needed to implement an SCR retrofit on a single unit and (b) about 19 months would be needed to implement an SNCR retrofit on a single unit.[233] The EPA also examined several particularly complicated implementation efforts and found that 34 months would be needed for a plant to install a maximum of 6 SCRs while 24 months would be needed for a plant to install a maximum of 10 SNCRs.[234] Finally, the EPA found that the necessary controls could be installed on EGUs without any disruptions in the supply of electricity because connections between a NO_X control system and a boiler can generally be completed in 5 weeks or less and thus could occur during the 5-week planned outage that each EGU typically has each year.[235]

Thus, for both EGUs and non-EGUs, EPA's technical analysis for the 1998 NO_X SIP Call indicated that a 3-year period would be sufficient for installation of both combustion and post-combustion controls, from the planning and specification of controls to completion of control technology implementation.[236] EPA's evaluation of the timeframes for post-combustion controls was based on the Agency's projection that 639 retrofit installations at EGU sources and 235 retrofit installations at non-EGU industrial sources would be necessary for existing sources in the covered states to comply with the NO_X SIP Call.[237] Although the scope of types of non-EGU sources covered by this proposed FIP is broader, and the estimated number of emissions units is greater (potentially including as many as 490 emissions units), than the scope and number of non-EGU sources evaluated in the 1998 NO_X SIP Call, and although a later analysis of timeframes for installation of post-combustion controls at EGUs produced a more refined estimate for that sector only,[238] EPA's prior analyses nonetheless inform the evaluation in this proposal of the necessary implementation schedule for non-EGU sources given they generally address NO_X control technologies similar to those that the EPA anticipates non-EGU sources may install to comply with the provisions of the proposed FIP

[227] However, as discussed in Section VII.B.1.c.i of this proposed rule, EPA's determinations in this regard are *not* based on a finding that the retrofit of post-combustion controls would not be feasible in the 2026 ozone season for all relevant units. The EPA finds that such retrofits are available and feasible on a fleetwide scale starting in the 2026 ozone season.

[228] Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD (''CSAPR Update Non-EGU TSD''), August 2016 (Table 3), available at *https://www.epa.gov/csapr/assessment-non-egu-NOx-emission-controls-cost-controls-and-time-compliance-final-tsd.* See also Institute of Clean Air Companies, SNCR Committee, ''White Paper, Selective Non-Catalytic Reduction (SNCR) For Controlling NO_X Emissions,'' at 5 (noting that ''SNCR retrofits typically do not require extended source shutdowns'').

[229] 63 FR 57356, 57448 (October 27, 1998). EPA generally anticipates that any required permitting processes may run concurrent with other steps in the installation processes and thus may not significantly lengthen the total time needed for installation.

[230] *Id.* at 57447–57449.

[231] Id. at 57447, 57449.

[232] Id. at 57448.

[233] Id.

[234] Id.

[235] Id.

[236] Id. at 57449.

[237] Id. at 57448 (Table V–1 and Table V–2).

[238] *See* Final Report, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies,'' EPA–600/R–02/073 (October 2002).

(*e.g.,* SCR, SNCR, low-NO_X burners and ultra-low NO_X burners).

Additionally, as part of EPA's evaluation of installation timing needs in the proposed CAIR (69 FR 4566), the EPA projected that it would take on average 21 months to install an SCR on one EGU unit, 27 months to install a scrubber on one EGU unit, and 3 years to install seven SCRs at a single EGU.[239] The EPA also noted that some EGUs could install SCR controls in as short of a period as 13 months.[240] This information and EPA's general experience indicate that a two-year installation timeframe for a rule requiring installation of new control technologies across a variety of emissions sources in several industries on a regional basis is a relatively fast installation timeframe, but that a 3-year installation timeframe should be feasible for most if not all of the identified industries. A shorter installation timeframe of approximately one year would likely raise significant challenges for sources, suppliers, contractors, and other economic actors, potentially including customers relying on the products or services supplied by the regulated sources. Thus, if the EPA finalizes this proposed rule in 2023, implementation of the necessary emissions controls across all of the affected non-EGU sources by the August 3, 2024, Moderate area attainment date would not be possible.

For purposes of this proposed rule, the EPA estimates that the required controls for non-EGU source categories would take up to 3 years to install across the affected industries in the 23 states that remain linked in 2026. Therefore, based on the available information, the EPA proposes to require compliance with these non-EGU control requirements by the beginning of the 2026 ozone season.

The EPA requests comment on the time needed to install the various control technologies across all of the emissions units in the Tier 1 and Tier 2 industries. In particular, the EPA solicits comment on the time needed to obtain permits (including the potential applicability of NSR requirements), the availability of vendors and materials, design, construction, and the earliest possible installation times for SCR on glass furnaces; SNCR or SCR on cement kilns; ultra-low NO_X burners, low NO_X burners, and SCR on ICI boilers (coal-fired, gas-fired, or oil-fired); low NO_X burners on large non-EGU ICI boilers; and low emissions combustion, layered emissions combustion, NSCR, and SCR on reciprocating rich-burn or lean-burn IC engines.

With respect to emissions monitoring requirements, EPA requests comment on the costs of installing and operating CEMS at non-EGU sources without NO_X emissions monitors; the time needed to program and install CEMS at non-EGU sources; whether monitoring techniques other than CEMS, such as predictive emissions monitoring systems (PEMS), may be sufficient for certain non-EGU facilities, and the types of non-EGU facilities for which such PEMS may be sufficient; and the costs of installing and operating monitoring techniques other than CEMS.

The EPA also requests comment on whether the FIP should provide a limited amount of time beyond the 2026 ozone season for individual non-EGU sources to meet the emissions limitations and associated compliance requirements, based on a facility-specific demonstration of necessity. As the D.C. Circuit stated in *Wisconsin,* the good neighbor provision may be read to allow for some deviation from the mandate to eliminate prohibited transport by downwind attainment deadlines, ''under particular circumstances and upon a sufficient showing of necessity,'' provided such deviation is ''rooted in Title I's framework [and] provide[s] a sufficient level of protection to downwind States.'' [241] Consistent with this directive, and recognizing that in general, the EPA aligns good neighbor obligations in the first instance with the last full ozone season before the downwind attainment date, the EPA requests comment on whether individual non-EGU sources should be allowed to request an extension of the May 1, 2026, compliance deadline by no more than 1 year (*i.e.,* to May 1, 2027) based on a sufficient showing of necessity. Any such comments should be supported by a detailed discussion of the facility-specific economic, technological, and other circumstances that may justify such an extension. The EPA notes that claims about infeasibility of controls are generally insufficient to justify an extension of time to comply, given the *Wisconsin* court's holding that the good neighbor provision requires upwind states to eliminate their significant contribution in accordance with the downwind states' attainment deadlines, without regard to questions of feasibility.[242]

The EPA solicits comment on the specific criteria that the EPA should apply in evaluating requests for extension of the 2026 compliance deadline for non-EGU sources. Such criteria could include documentation of inability, despite best efforts, to procure necessary materials or equipment (*e.g.,* equipment manufacturers are not able to deliver equipment before a specific date) or hire labor as needed to install the emissions control technology by 2026; documentation of installation costs well in excess of the highest representative cost-per ton threshold identified for any source (including EGUs) discussed in Section VI of this proposed rule (*e.g.,* vendor estimate showing equipment cost); documentation of a source owner or operator's inability to secure necessary financing, due to circumstances beyond the owner/operator's control, in time to complete the installation of controls by 2026; or documentation of extreme financial or technological constraints that would require the subject non-EGU emissions unit or facility to significantly curtail its operations or shut down before it could comply with the requirements of this proposed rule by 2026. Finally, the EPA requests comment on the process through which the EPA should review and act on an extension request—*e.g.,* the appropriate deadline for submitting a request, and whether the EPA should provide an opportunity for public comment before granting or denying a request.

The EPA anticipates that the owner or operator of the facility would bear the burden of establishing the necessity of an extension of time to comply, based on particular circumstances described and sufficiently documented in the submitted request. Claims of generalized financial or economic hardship or any claim that controls are not necessary to eliminate significant contribution would

[239] 69 FR 4566, 4617 (January 30, 2004) (citing Final Report, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies,'' EPA–600/R–02/073 (October 2002)).

[240] Final Report, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies,'' EPA–600/R–02/073 (October 2002), at 21.

[241] *Wisconsin,* 938 F. 3d at 320 (citing CAA section 181(a) (allowing one-year extension of attainment deadlines in particular circumstances) and *North Carolina,* 531 F.3d at 912).

[242] *Wisconsin,* 938 F.3d at 313–314, 319 (''When an agency faces a statutory mandate, a decision to disregard it cannot be grounded in mere infeasibility''). We note also that in the CSAPR Close-Out Rule (83 FR 65878, December 21, 2018), the EPA required no further reductions from upwind states beyond those set forth in the prior CSAPR Update based, in part, on the Agency's conclusion that it was not feasible to implement cost-effective emissions controls before 2023, 2 years after the 2021 attainment deadline for the downwind serious areas. The D.C. Circuit vacated the Close-Out Rule for its reliance on the same interpretation of the Good Neighbor Provision that the court had rejected in *Wisconsin. New York* v. *EPA,* 781 F. App'x 4 (D.C. Cir. 2019) (unpublished opinion).

not suffice to justify an extension. If the EPA finalizes a provision allowing sources to request limited extensions of time to comply, the Agency would review each request on a case-by-case basis as necessary to ensure consistency with the provisions of title I of the CAA.

B. Regulatory Requirements for EGUs

To implement the required emissions reductions from EGUs, the EPA proposes to revise the existing CSAPR NO_X Ozone Season Group 3 Trading Program (the ''Group 3 trading program'') established in the Revised CSAPR Update both to expand the program's geographic scope and to enhance the program's ability to ensure favorable environmental outcomes.[243] The EPA proposes to use a trading program for EGUs because of the inherently greater flexibility that a trading program can provide relative to more prescriptive, ''command-and-control'' forms of regulation of sufficient stringency to achieve the necessary emissions reductions. In the electric power sector, EGUs' extensive interconnectedness and coordination create the ability to shift both electricity production and emissions among units, providing a closely related ability to achieve emissions reductions in part by shifting electricity production from higher-emitting units to lower-emitting or non-emitting units. The sector's unusual flexibility with respect to how emissions reductions can be achieved makes the flexibility of a trading program particularly useful as a means of lowering the overall costs of obtaining such reductions. In addition, it is essential for the electric power sector to retain short-term operational flexibility sufficient to allow electricity to be produced at all times in the quantities needed to meet demand simultaneously, and the flexibility of a trading program can be helpful in supporting this aspect of the industry as well. As discussed later, to provide improved environmental outcomes, in this rulemaking, the EPA is proposing certain enhancements to the current provisions of the Group 3 trading program addressing environmental performance that will necessarily reduce the flexibility of the individual units participating in the program to some extent. However, with the proposed enhancements, the EPA believes the inherently greater flexibility of a trading program continues to favor the use of this form of regulation, relative to more prescriptive forms of regulation, as a vehicle for achieving the emissions reductions from the electric power sector found to be necessary in this rulemaking.

The Group 3 trading program currently applies to EGUs meeting the program's applicability criteria within the borders of twelve states: Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia. Affected EGUs in these twelve states would continue to participate in the Group 3 trading program as revised in this rulemaking, with some revised provisions taking effect in the 2023 control period and other revised provisions taking effect later as discussed elsewhere in this document. The EPA proposes to expand the Group 3 trading program's geographic scope to include all of the additional states for which EGU emissions reduction requirements are being established in this rulemaking. Affected EGUs within the borders of eight states currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program (the ''Group 2 trading program'')—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—would transition from the Group 2 program to the revised Group 3 trading program at the beginning of the 2023 control period,[244] and affected EGUs within the borders of the five states not currently covered by any CSAPR trading program for seasonal NO_X emissions—Delaware, Minnesota, Nevada, Utah, and Wyoming—would enter the Group 3 trading program in the 2023 control period following the effective date of a final rule in this rulemaking. As is the case for the states already in the Group 3 trading program, for each state added to the program, the set of affected EGUs would include new units as well as existing units and units located in Indian country within the state's borders as well as units not located in Indian country. Sections VII.B.2 and VII.B.3 of this proposed rule provide additional discussion of the proposed geographic expansion of the Group 3 trading program and the units in the expanded geography that would likely become subject to the program under the program's existing applicability provisions.

In addition to expanding the Group 3 trading program's geographic scope, the EPA proposes to modify the program's regulations prospectively to include certain enhancements to improve environmental outcomes. Two of the proposed enhancements would adjust the overall quantities of allowances available for compliance in the trading program in each control period so as to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves. First, instead of establishing emissions budgets for all future years under the program at the time of the rulemaking, which cannot reflect future changes in the EGU fleet unknown at the time of the rulemaking, the EPA proposes to revise the trading program regulations to include a dynamic budgeting procedure. This procedure would calculate emissions budgets for control periods in 2025 and later years based on more current information about the composition and utilization of the EGU fleet, specifically data available from the 2023 ozone season and following (*e.g.,* for 2025, data from 2023; for 2026, data from 2024; etc.). (Associated revisions to the program's variability limits and unit-level allowance allocation procedures would coordinate these provisions with the revised budget-setting procedures.) Second, starting with the 2024 control period, the EPA proposes to annually recalibrate the quantity of accumulated banked allowances under the program to prevent the quantity of allowances carried over from each control period to the next from exceeding the target bank level, which would be revised to represent 10.5 percent of the sum of the state emissions budgets. Together, these enhancements would protect the intended stringency of the trading program against potential erosion caused by EGU fleet turnover and would better sustain over time the incentives created by the trading program to apply continuously the degree of emissions control the EPA determines is necessary to address states' good neighbor obligations.

Two further enhancements to the Group 3 trading program proposed in this rulemaking would establish provisions designed to promote more consistent emissions control by individual EGUs within the context of the trading program. First, starting with the 2024 control period for most coal-fired EGUs with existing SCR controls and the 2027 control period for most other coal-fired EGUs, a daily NO_X emissions rate of 0.14 lb/mmBtu would

[243] If any of the states whose sources currently participate in the Group 3 trading program is determined in the final rule to not have additional emissions reduction requirements for EGUs, the EPA proposes in the alternative to establish a new trading program substantially similar to the revised Group 3 trading program described in this proposal that would cover units within the borders of all the states determined to have emissions reduction requirements for EGUs in the final rule.

[244] Affected EGUs in the two other states currently covered by the Group 2 trading program—Iowa and Kansas—would continue to participate in that program.

apply as a backstop to the more stringent seasonal emissions budgets. Each ton of emissions exceeding a unit's backstop daily emissions rate would incur a 3-for-1 allowance surrender ratio instead of the usual 1-for-1 allowance surrender ratio. Second, also starting with the 2024 control period, the trading program's existing assurance provisions, which require extra allowance surrenders from sources that are found responsible for contributing to an exceedance of the relevant state's ''assurance level'' (*i.e.,* currently 121 percent of the state's emissions budget), would be strengthened by the addition of another backstop requirement. Specifically, for any unit found responsible for contributing to an exceedance of the state's assurance level, the revised regulations would prohibit the unit's seasonal emissions from exceeding by more than 50 tons the emissions that would have resulted if the unit had achieved a seasonal average emissions rate equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest previous seasonal average emissions rate under any CSAPR seasonal NO_X trading program.[245]

These two enhancements are designed to ensure that all individual units with SCR controls have strong incentives to continuously operate and optimize their controls, and also to ensure that even units without SCR controls have strong incentives to optimize their emissions performance when a state's assurance level might otherwise be exceeded. These enhancements are generally designed to ensure consistency with EPA's determination regarding the emissions control stringency needed from EGUs to eliminate significant contribution under the Step 3 multifactor analysis as discussed in Section VI of this proposed rule. Further, these enhancements are designed to provide greater assurance that emissions controls will be operated on all days of the ozone season and therefore necessarily on the days that turn out to be most critical for downwind ozone levels. The EPA expects that promoting more consistently good emissions performance by individual EGUs will also help address disparate impacts of pollution on overburdened communities from individual units that might otherwise have chosen not to optimize their emissions performance.

[245] The requirement would not apply for control periods during which the unit operated for less than 10 percent of the hours, and emissions rates achieved in such previous control periods would be excluded from the comparison.

1. Trading Program Background and Overview of Proposed Revisions

a. Current CSAPR Trading Program Design Elements and Identified Concerns

The use of allowance trading programs to achieve required emissions reductions from the electric power sector has a long history, rooted in the Clean Air Act Amendments of 1990. In Title IV of those amendments, Congress specified the design elements for a 48-state allowance trading program to reduce SO_2 emissions and the resulting acid precipitation. Building on the success of that first allowance trading program as a tool for addressing multi-state air pollution issues, since 1998 EPA has promulgated and implemented multiple allowance trading programs for SO_2 or NO_X emissions to address the requirements of the CAA's good neighbor provision with respect to successively more stringent NAAQS for fine particulate matter and ozone. Most of these trading programs have applied either exclusively or primarily to EGUs.

The EPA currently administers six CSAPR trading programs for EGUs (promulgated in CSAPR, the CSAPR Update, and the Revised CSAPR Update) that differ in the pollutants, geographic regions, and time periods covered and in the levels of stringency, but that otherwise are nearly identical in their core design elements and their regulatory text.[246] The principal common design elements currently reflected in all of the programs are as follows:

- An ''emissions budget'' is established for each state for each control period, representing EPA's quantification of the emissions that would remain under certain projected conditions after elimination of the emissions prohibited by the good neighbor provision under those projected conditions. For each control period of program operation, a quantity of newly issued ''allowances'' equal to the amount of each state's emissions budget is allocated among the state's sources. (States have options to replace EPA's default allocations or to institute an auction process.) Total emissions in a given control period from all sources in the program are effectively capped at a level no higher than the total quantity of allowances available for use in the control period, consisting of the sum of all states' emissions budgets for the control period plus any unused allowances carried over from previous control periods as ''banked'' allowances.
- ''Assurance provisions'' in each program establish an ''assurance level'' for each state for each control period, defined as the sum of the state's emissions budget plus a specified ''variability limit.'' The purpose of the assurance provisions is to limit the total emissions from each state's sources in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's mandate that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability. In the event a state's assurance level is exceeded, responsibility for the exceedance is apportioned among the state's sources through a procedure that accounts for the sources' shares of the state's total emissions for the control period as well as the sources' shares of the state's assurance level for the control period.
- At the program's compliance deadlines after each control period, sources are required to hold for surrender specified quantities of allowances. The minimum quantities of allowances that must be surrendered are based on the sources' reported emissions for the control period at a 1-for-1 ratio of allowances to tons of emissions (or 2-for-1 in instances of late compliance). In addition, two more allowances must be surrendered for each ton of emissions exceeding a state's assurance level for a control period, yielding an overall 3-for-1 surrender ratio for those emissions (or 4-for-1 in instances of late compliance). Failure to timely surrender all required allowances is potentially subject to penalties under the CAA's enforcement provisions.
- To continuously incentivize sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, and to promote compliance cost minimization, operational flexibility, and allowance market liquidity, the programs allow trading of allowances—both among sources in the program and with non-source entities—and also let allowances that are unused in one control period be carried over for use in future control periods as banked allowances. Although the programs do not directly limit either trading or banking of allowances, the 3-for-1 surrender ratio imposed by the

[246] The six current CSAPR trading programs are the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR SO_2 Group 1 Trading Program, CSAPR SO_2 Group 2 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR NO_X Ozone Season Group 3 Trading Program. The regulations for the six programs are set forth at subparts AAAAA, BBBBB, CCCCC, DDDDD, EEEEE, and GGGGG, respectively, of 40 CFR part 97.

assurance provisions on any emissions exceeding a state's assurance level disincentivizes sources from relying on either in-state banked allowances or net out-of-state purchased allowances to emit over the assurance level.

• Finally, other common design elements ensure program integrity, source accountability, and administrative transparency. Most notably, each unit must monitor and report emissions and operational data in accordance with the provisions of 40 CFR part 75; all allowance allocations or auction results, transfers, and deductions must be properly recorded in EPA's Allowance Management System; each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account; and comprehensive data on emissions and allowances are made publicly available.

The EPA continues to believe that the current CSAPR trading program structure established by the common design elements described previously has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide to a sector such as the electric power sector where such flexibility is especially useful and valuable. However, the EPA also shares some stakeholders' concerns about whether the current structure, without enhancements, is capable of adequately addressing states' good neighbor obligations with respect to the 2015 ozone NAAQS in light of the rapidly evolving EGU fleet and the stringency and short-term form of the standard. One set of concerns relates to the observed tendency under the current trading programs for the supply of allowances to grow over time while the demand for allowances falls, reducing allowance prices and eroding the consequent incentives for sources to effectively control their emissions. A second, overlapping set of concerns relates to the general absence of source- or unit-specific emissions reduction requirements, allowing some individual sources to idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard and also have the potential to cause disproportionate adverse impacts on downwind overburdened communities. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. In an effort to maintain as much compliance and operational flexibility as possible, ensure controls happen on critically important highest ozone days, guard against this behavior under a more stringent NAAQS, and provide relief to overburdened communities, the EPA would require control operation every day through a unit-level emission rate designed to ensure reductions occur on the highest ozone days in addition to maintaining a mass-based seasonal requirement. To meet the statutory requirement to eliminate significant contribution and interference with maintenance on the critically important days, this combination of requirements would require sources to plan to run controls all season, including the highest ozone days, while giving reasonable flexibility for occasional operational needs.

In this rulemaking, the EPA is proposing to revise the Group 3 trading program to include enhancements designed to address both sets of concerns described above.[247] The principles guiding the various proposed revisions and the relationships of the revisions to one another are discussed in Sections VII.B.1.b and VII.B.1.c of this proposed rule. The individual proposed revisions are discussed in more detail in Sections VII.B.4 through VII.B.9 of this proposed rule.

b. Enhancements To Maintain Selected Control Stringency Over Time

The first set of concerns noted about the current CSAPR trading program structure relates to the programs' ability to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time. Under the structure of the current CSAPR trading programs, the effectiveness of the programs at maintaining the rule's selected control stringency depends entirely on how allowance prices over time compare to the costs of sources' various emissions reduction opportunities, which in turn depends on the relationship between the supply for allowances and the demand for allowances. In considering possible ways to address concerns about the ability to enhance the current trading program structure to better sustain incentives to control emissions over time, the EPA has focused on the trading program design elements that determine the supply of allowances, specifically the approach for setting state emissions budgets and the rules concerning the carryover of unused allowances for use in future control periods as banked allowances.

i. Revised Emissions Budget-Setting Process

In each of the previous rulemakings establishing CSAPR trading programs, the EPA has evaluated the emissions that could be eliminated through implementation of certain types of emissions control strategies available at various cost thresholds to achieve certain rates of emissions per unit of heat input (*i.e.,* the amount of fuel consumed) and the effects of the resulting emissions reductions on downwind air quality. After determining the emissions control strategies and associated emissions reductions that should be required under the good neighbor provision by considering these factors in a multifactor test, the EPA has then projected the amounts of emissions that would remain after the assumed implementation of the selected emissions control strategies at various points in the future and has established the projected remaining amounts of emissions as the state emissions budgets in trading programs.

Projecting the amounts of emissions remaining after implementation of selected emissions controls necessarily requires projections not only for sources' future emissions rates but also for other factors that influence total emissions, notably the composition of the future EGU fleet (*i.e.,* the capacity amounts of different types of sources with different emissions rates) and their future utilization levels (*i.e.,* their heat input). To the extent the projections made at the time of a rulemaking for these other factors prove inaccurate, over time the emissions budgets may not reflect the intended stringency of the emissions control strategies identified in the rulemaking as consistent with addressing states' good neighbor obligations. Further, projecting EGU fleet composition and utilization has become increasingly challenging in light of the rapid evolution of the electric power sector toward more efficient and cleaner sources of generation, driven by factors including lower prices for natural gas and wind and solar generation.

[247] With the exception of the proposed conforming revisions to allowance recordation schedules discussed in Section VII.B.12 of this proposed rule, the EPA is not proposing in this rulemaking to extend the enhancements proposed for the Group 3 trading program to the other CSAPR trading programs.

A consequence of using a trading program approach with preset emissions budgets that do not keep pace with the trends in EGU fleet composition and heat input is that the preset emissions budgets maintain the supply of allowances at levels that increasingly exceed the emissions that would occur even without implementation of the emissions control strategies used as the basis for determining the emissions budgets, causing decreases in allowance prices and hence the incentives to implement the control strategies. As an example, although the emissions budgets in the CSAPR Update established in 2016 reflected implementation of the emissions control strategy of operating and optimizing existing SCR controls, within 4 years the EPA found that EGU retirements and changes in utilization not anticipated in EPA's previous budget-setting computations had made it economically attractive for at least some sources to idle or reduce the effectiveness of their existing controls (relying on purchased allowances instead).[248] While the EPA has provided analysis indicating that, on average, sources operate their controls more effectively on high electric demand days, it has also identified cases where units fail to optimize their controls on these days. Downwind states have suggested this type of reduced pollution control performance has occurred on the day and preceding day of an ozone exceedance.[249] [250] Such an outcome undermined the ongoing achievement of emissions rate performance consistent with the control strategies defined to eliminate significant contribution to nonattainment and interference with maintenance, including continuous operation and optimization of existing controls.

In the Revised CSAPR Update, the EPA took steps to better address the rapid evolution of the EGU fleet, specifically by setting updated emissions budgets for individual future years though 2024 that reflect future EGU fleet changes known with reasonable certainty at the time of the rulemaking. Some commenters requested that the EPA also update the year-by-year emissions budgets to reflect future fleet changes that might become known after the time of the rulemaking, but the EPA declined to do so, in part because no methodology for making future emissions budget adjustments in response to post-rulemaking data had been included in the proposal for the rulemaking.

Based on information available as of December 2021, it appears that the emissions budgets set for the first control period covered by the Revised CSAPR Update generally succeeded at creating incentives to operate emissions controls under the Group 3 trading program for the programs' first control period. However, the EPA recognizes that the lack of emissions budget adjustments after 2024 in conjunction with industry trends toward more efficient and cleaner resources would likely lead to a surplus of allowances after the adjustments end. In this rulemaking, besides setting new emissions budgets for the 2023 and 2024 control periods, the EPA also proposes to extend the Group 3 trading program budget-setting methodology used in the Revised CSAPR Update to routinely set emissions budgets for each future control period in the year before that control period, with each emissions budget reflecting the latest available information on the composition and utilization of the EGU fleet at the time that emissions budget is determined.

The current budget-setting methodology established in the Revised CSAPR Update and the proposed revisions are discussed in detail in Section VII.B.4 of this proposed rule and the Ozone Transport Policy Analysis Proposed Rule TSD. To summarize here, the Revised CSAPR Update's emissions budget-setting methodology includes three primary steps: (1) Establishment of a baseline inventory of EGUs adjusted for known retirements and new units, with heat input and emissions rate data for each EGU in the inventory based on recent historical data; (2) adjustment of the baseline data to reflect assumed emissions rate changes resulting from known new controls, known gas conversions, and implementation of the emissions control strategies used to determine states' good neighbor obligations; and (3) application of an increment or decrement to reflect the effect on emissions from projected generation shifting among the units in a state at the emissions reduction cost associated with the selected emissions control strategies. In this rulemaking, the EPA proposes to modify this methodology in two ways. First, the baseline EGU inventory and heat input data, but not the emissions rate data, would be updated for each control period using the most recent available reported data. For example, in early 2024, using the final data reported for 2023, the EPA would update the baseline inventory and heat input data used to determine state emissions budgets for the 2025 control period. Second, the EPA would not apply an increment or decrement to any state emissions budget for projected generation shifting associated with implementation of the selected control strategies, because any such shifting should already be reflected in the heat input data used to update the baseline.[251]

The EPA believes that the proposed revisions to the emissions budget-setting process would substantially improve the ability of the emissions budgets to keep pace with changes in the composition and utilization of the EGU fleet. The revised methodology would account for the electric power sector's overall trends toward more efficient and cleaner resources, both of which tend to decrease total heat input at affected EGUs. The revised methodology would also account for other factors that could lead to increased heat input in some states, such as generation shifting from other states or increases in electricity demand caused by rising electrification. The updating procedure would be specified in the program regulations and the computations, which would be straightforward, could be performed in a spreadsheet to deliver reliable results. EPA would provide public notice of the preliminary calculations and the data used by March 1 of the year preceding the control period and would provide an opportunity for submission of any objections to the data and preliminary calculations before finalizing the budgets for each control period by May 1 of the year before the control period to which those budgets apply. Thus, for example, sources and other stakeholders will have certainty by May 1, 2024, of the emissions budgets that will be set for the 2025 control period that starts May 1, 2025.

[248] The price of allowances in CSAPR Update states started out at levels near $800 per ton in 2017 but declined to less than $100 per ton by 2019 and were less than $70 per ton in July 2020 (data from S&P Global Market Intelligence).

[249] 86 FR 23117.

[250] *See EPA–HQ–OAR–2020–0272–0094.* ''. . . is demonstrated through examination of Maryland's ozone design value days for June 26th–28th, 2019. On those days, Maryland recorded 8-hour ozone levels of 75, 85 and 83 ppb at the Edgewood monitor. Maryland Department of the Environment evaluated the daily NO_X emission rate for units in Pennsylvania that were found to influence the design values on the 3 exceedance days (and 1 day prior to the exceedance) against the past-best ozone season 30-day rolling average optimized NO_X rate (which tends to be higher than the absolute lowest seasonal average rate).''

[251] Emission reductions derived from generation shifting will be captured in the dynamic budgets in all cases. For the pre-set budget years it is estimated and incorporated through an additional calculation step. For dynamic budget years, it is directly incorporated through the inclusion of updated heat input data reflecting observed, compliance period generation shifting.

It bears emphasis that the annually updated information would concern only the composition and utilization of the EGU fleet and not the emissions rate data also used in the emissions budget computations. The emissions budget computations for all years would reflect only the specific emissions control strategies used to determine states' good neighbor obligations as determined in this rulemaking, along with fixed historical emissions rates for units that are not assumed to implement additional control strategies, thereby ensuring that the annual updates would eliminate emissions as determined to be required under the good neighbor provision. The stringency of the emissions budgets would simply reflect the stringency of the emissions control strategies determined in the Step 3 multifactor analysis and would do so more consistently over time than EPA's previous approach of computing emissions budgets for all future control periods at the time of the rulemaking.

The proposed revisions to state emissions budgets and the budget-setting process are discussed further in Section VII.B.4 of this proposed rule. Proposed coordinated revisions to the determination of state-level variability limits and assurance levels and to unit-level allowance allocations are discussed in Sections VII.B.5 and VII.B.9 of this proposed rule, respectively.

ii. Allowance Bank Recalibration

Besides the levels of the emissions budgets, the second design element of the trading program structure that affects the supply of allowances in each control period, and that consequently also affects the ability of a trading program to maintain the rule's selected control stringency and related EGU effective emissions rate performance level as the EGU fleet evolves over time, is the set of rules concerning the carryover of unused allowances for use in future control periods as banked allowances. As noted previously, trading and banking of allowances in the CSAPR trading programs can serve a variety of purposes: Continuously incentivizing sources to reduce their emissions even when they already hold sufficient allowances to cover their expected emissions for a control period, facilitating compliance cost minimization, accommodating necessary operational flexibility, and promoting allowance market liquidity. All of these purposes are advanced by rules that allow sources to trade allowances freely (both with other sources and with non-source entities such as brokers). All of these purposes are also advanced by rules that allow unused allowances to be carried over for possible use in future control periods, thereby preserving a value for the unused allowances. However, while the EPA considers it generally advantageous to place as few restrictions on the trading of allowances as possible,[252] unrestricted banking of allowances has a potentially significant disadvantage offsetting its advantages, namely that it allows what might otherwise be temporary surpluses of allowances in some individual control periods to accumulate into a long-term allowance surplus that reduces allowances prices and weakens the trading program's incentives to control emissions. With weakened incentives, some operators would be more likely to choose not to continuously operate and optimize their emissions controls, imperiling the ongoing achievement of emissions rate performance consistent with the control strategies defined as eliminating significant contribution to nonattainment and interference with maintenance.

As discussed in detail in Section VII.B.6 of this proposed rule, the EPA is proposing to revise the Group 3 trading program by adding provisions that would establish a routine recalibration process for banked allowances that would be carried out in August 2024 and each subsequent August, after the compliance deadline for the control period in the previous year. In each recalibration, the EPA would reset the total quantity of banked allowances for the Group 3 trading program (''Group 3 allowances'') held in all Allowance Management System accounts to a target level of 10.5 percent of the sum of the state emissions budgets for the current control period. The procedure would entail identifying the ratio of the target bank amount to the total quantity of banked allowances held in all accounts before the conversion and then, if the ratio was less than 1.0, multiplying the quantity of banked allowances held in each account by the ratio to identify the appropriate recalibrated amount for the account (rounded to the nearest allowance), and deducting any allowances in the account exceeding the recalibrated amount.

The EPA believes this revision to the Group 3 trading program's banking provisions would complement the proposed revisions to the budget-setting process by ensuring that the annual bank recalibration would prevent any surplus of allowances created in one control period from diminishing the intended stringency and resulting emissions reductions of the emissions budgets for subsequent control periods.[253]

The calibration procedure would not erase the value of unused allowances for the holder, because the larger the quantity of banked allowances that is held in a given account before each recalibration, the larger the quantity of banked allowances that would be left in the account after the recalibration for possible sale or use in meeting future compliance requirements. Because the banked allowances would always have value, the opportunity to bank allowances would continue to advance the purposes served by otherwise unrestricted banking as described above. Opportunities to bank unused allowances can serve all these same purposes whether a banked allowance is of partial value (if the bank needs recalibrating to its target level) or is of full value compared to a newly issued allowance for the next control period.

The proposal to routinely recalibrate the allowance bank is discussed further in Section VII.B.6 of this proposed rule.

d. Enhancements To Improve Emissions Performance at Individual Units

The second set of concerns about the structure of the current CSAPR trading programs relates to the general absence of source- or unit-specific emissions reduction requirements. Without such requirements, the programs affect individual sources' emissions

[252] The advantages of trading programs discussed earlier in this section—providing continuous emissions reduction incentives, facilitating compliance cost minimization, and supporting operational flexibility—depend on the existence of a marketplace for purchasing and selling allowances, and broader marketplaces generally provide greater market liquidity and therefore make trading programs better at providing these advantages. The EPA recognizes that unrestricted use of *net* purchased allowances—meaning quantities of purchased allowances that exceed the quantities of allowances sold—by a source or group of sources as an alternative to making emissions reductions can interfere with the achievement of the desired environmental outcome, and Section VII.B.1.c of this proposed rule discusses the enhancements to the Group 3 trading program that the EPA is proposing in this rulemaking to reduce reliance on net purchased allowances by incentivizing or requiring better environmental performance at individual EGUs. However, the concern arises from the *use of an excessive quantity* of net purchased allowances for a particular purpose, not from the existence of a *marketplace* where allowances may be freely bought and sold.

[253] The EPA recognizes there will be a data lag inherent in the future year emissions budgets, because the budgets would reflect fleet composition and utilization data reported for a previous control period. This means that the budgets for some individual control periods may fail to fully keep pace with the EGU fleet's trends toward more efficient and cleaner resources. Nonetheless, the new approach is a substantial improvement in environmental performance of the program compared to a more unlimited approach to allowance banking.

performance only to the extent that the incentives created by allowance prices are high enough relative to the costs of the sources' various emissions control opportunities. In circumstances where the incentives to control emissions are insufficient, some individual sources even idle existing emissions controls. Emissions from these individual sources can contribute to increased pollution concentrations downwind on the particular days that matter for downwind exceedances of the relevant air quality standard and also have the potential to cause disproportionate adverse impacts on downwind overburdened communities.

This EPA intends that the trading program enhancements described in Section VII.B.1.b of this proposed rule would improve the Group 3 trading program's ability to sustain emissions control incentives over time such that needed emissions performance would be achieved by all participating units without the need for additional requirements to be imposed at the level of individual units. However, because obtaining needed emissions performance at individual units is also important, the EPA proposes to supplement the previously discussed enhancements with two other new sets of provisions that would apply to certain individual units within the larger context of the Group 3 trading program. The allowance price would continue to be the most important driver of good environmental performance for most units, but the proposed unit-level requirements would be important supplemental drivers of performance and would offer additional assurance that significant contribution is eliminated on a daily basis during the ozone season by continuous operation of existing pollution controls.

i. Unit-Specific Backstop Daily Emissions Rates

The first of the proposed trading program enhancements intended to improve emissions performance at the level of individual units is the addition of backstop daily NO_X emissions rate provisions that would apply to large coal-fired EGUs, defined for this purpose as units serving electricity generators with nameplate capacities equal to or greater than 100 MW and combusting any coal during the control period in question. Starting with the 2024 control period, a 3-for-1 allowance surrender ratio (instead of the usual 1-for-1 surrender ratio) would apply to emissions during the ozone season from any large coal-fired EGU with existing SCR controls exceeding a daily average NO_X emissions rate of 0.14 lb/mmBtu. The additional allowance surrender requirement would be integrated into the trading program as a new component in the calculation of each unit's primary emissions limitation, such that the additional allowances would have to be surrendered by the same compliance deadline of June 1 after each control period. The amount of additional allowances to be surrendered would be determined by computing, for each day of the control period, any excess of the unit's reported emissions (in pounds) over the emissions that would have resulted from combusting that day's actual heat input at an average daily emissions rate of 0.14 lb/mmBtu, summing the daily amounts, converting from pounds to tons, and multiplying by two. Starting with the 2027 control period, the 3-for-1 surrender ratio would apply in the same way to all large coal-fired EGUs, consistent with EPA's proposed determinations, first, that a control stringency reflecting installation and operation of SCR controls on all large coal-fired EGUs is appropriate to address states' good neighbor obligations with respect to the 2015 ozone NAAQS, and second, that such controls could reasonably be installed by the 2026 control period.

In prior rules addressing interstate transport of air pollution, stakeholders have noted that while seasonal cap-and-trade programs are effective at lowering ozone and ozone-forming precursors across the ozone season, attainment of the standard is measured on key days and therefore it is necessary to ensure that the rule requires emissions reductions not just seasonally, but also on those key days.[254] They have noted that while the trading programs established under the NO_X SIP Call, CAIR, and CSAPR have all been successful in ensuring seasonal reductions, states must remain below daily peak levels, not just seasonal levels, to reach attainment. These downwind stakeholder communities have suggested that operating pollution controls on the highest ozone days (and immediately preceding days) during the ozone season is of critical importance. The EPA has analyzed hourly emissions data reported in prior cap-and-trade programs and has identified instances of sources that did not operate SCR controls for substantial portions of recent ozone seasons. These instances are discussed below and in the EGU NO_X Mitigation Strategies Proposed Rule TSD in the docket. While the EPA has in prior ozone transport actions not found sufficient evidence of emissions control idling or non-operation to take the step of building in enhancements to the trading program to ensure unit-level control operation, our review of that information applied to this context suggests this problem could become more prevalent in future years relevant to this action. Rather than allow for the potential of continued deterioration in the environmental performance of our trading programs, the EPA finds the evidence of declining SCR performance in later years of trading programs sufficient to justify prophylactic measures in this proposal to ensure the emissions control strategy selected at Step 3 is indeed implemented at Step 4. Thus, particularly in the context of the more stringent 2015 ozone NAAQS combined with the full remedy nature of this action and the extended timeframe for which upwind contribution to downwind nonattainment is projected to persist, the EPA agrees with these stakeholders that the set of measures promulgated in this rulemaking to implement the control stringency levels found necessary to address states' good neighbor obligations should include measures designed to more effectively ensure that individual units operate their emission controls routinely throughout the ozone season, thereby also ensuring that the controls are planned to be in operation on the particular days that turn out to be most critical for ozone formation and for attainment of the NAAQS.[255] Routine operation of emissions controls will also provide relief to overburdened communities downwind of any units that might otherwise have chosen not to operate their controls. In the Ozone Transport TSD, the EPA conducted a screening analysis that found nearly all of the EGUs included in this analysis are located within a 24-hour transport distance of many areas with potential EJ concerns. The EPA is proposing to adopt backstop daily rate limits at the individual unit level for this purpose, implemented in the context of a trading program (*i.e.,* through enhanced allowance surrender ratios), as an alternative to adopting enforceable rate limits.

The purpose of establishing a backstop daily NO_X emissions rate and implementing it through additional

[254] EPA–HQ–OAR–2020–0272. Comment submitted by Ben Grumbles, Secretary, Maryland Department of the Environment (MDE).

[255] The CSAPR Update was a partial remedy and the Revised CSAPR Update addressed downwind nonattainment and maintenance issues that were projected to be resolved within a 4 year window. In contrast, this rule reflects a full remedy and is addressing downwind nonattainment and maintenance issues that are projected to persist for more than a decade.

allowance surrender requirements instead of as an enforceable rate limit is to incentivize improved emissions performance at the individual unit level while continuing to preserve, to the extent possible, the advantages that the flexibility of a trading program brings to the electric power sector. As discussed in Section VII.B.7 of this proposed rule, under existing trading programs without the enhancements proposed in this rulemaking, some individual coal-fired units with SCR controls have chosen to operate the controls at lower removal efficiencies than in past ozone seasons or even to idle the controls for entire ozone seasons. In addition, some SCR-equipped units have chosen to routinely cycle their emissions controls off at lower load levels, such as while operating overnight, instead of operating the controls, upgrading the units to enable the controls to be operated under those conditions, or not operating the units under those conditions.

The EPA has identified sources of interstate ozone pollution such as the New Madrid and Conemaugh plants (in Missouri and Pennsylvania, respectively) whose SCR controls were not operating for substantial portions of recent ozone seasons. The data in Figures 1 and 2 to Section VII.B.1.c.i, included in Appendix G of the Ozone Transport Policy Analysis Proposed Rule TSD available in the docket for this rulemaking, demonstrate that these units have operated their SCRs better and more consistently during years with higher NO_X allowance prices. Downwind stakeholders have noted that some of the higher emission rates (specifically in the case of Conemaugh Unit 2 in 2019) have occurred on the day of and the preceding day of an ozone exceedance in bordering states.[256]

The EPA believes that the design of the proposed daily emissions rate provisions would be effective in addressing these types of high-emitting behavior by significantly raising the cost of planned operator decisions that substantially compromise environmental performance. At the same time, the provision would not unduly penalize an occasional unplanned exceedance, because the amount of additional allowances that would have to be surrendered to address a single day's exceedance would be much smaller than the amount that would have to be surrendered to address planned poor performance sustained over longer time periods.[257]

The EPA proposes to apply the daily emissions rate provisions to large coal-fired EGUs, and not to other types of units, for reasons that are consistent with EPA's determinations regarding the appropriate control stringency for EGUs to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. Installation and operation of SCR controls is well-established as best practice for control of NO_X emissions from coal-fired EGUs, as evidenced by the fact that the technology is already installed on more than 60 percent of the sector's total coal-fired capacity. In the context of the need for states to address their good neighbor obligations with respect to the 2015 ozone NAAQS, the EPA is proposing to determine that a control stringency reflecting universal installation and operation of SCR technology at large coal-fired EGUs is appropriate, based on a multi-factor test that includes consideration of cost-effectiveness along with air quality factors. Finally, where SCR controls are installed, optimized operation of those controls is an extremely cost-effective method of achieving NO_X emissions reductions. The EPA believes these considerations support establishment of the proposed daily emissions rate provisions on a universal basis for large coal-fired EGUs, with near-term application of the provisions for units that already have the controls installed and deferred application for other units, as discussed later.

With regard to gas-fired steam EGUs, SCR controls are nowhere near as prevalent, and while the EPA is proposing to include some SCR controls at gas-fired steam units in the selected control stringency, the EPA is not proposing to include universal SCR controls at gas-fired steam units. Because the EPA does not propose to determine that universal installation and operation of SCR controls at gas-fired steam EGUs is part of the selected control stringency, in order not to constrain the power sector's flexibility to choose which particular gas-fired steam EGUs are the preferred candidates for achieving the required emissions reductions, the EPA is not proposing to apply the daily emissions rate provisions to large gas-fired steam EGUs. Focusing the backstop daily emissions rates on coal-fired units is also consistent with stakeholder input which has emphasized the need for short-term rate limits at coal units given their relatively higher emissions rates.

The EPA developed the proposed level of the daily average NO_X emissions rate—0.14 lb/mmBtu—through analysis of historical data, as described in Section VII.B.7 of this proposed rule. A rate of 0.14 lb/mmBtu represents the daily average NO_X emissions rate that has been demonstrated to be achievable on approximately 95 percent of days covering more than 99 percent of total ozone-season NO_X emissions by coal-fired units with SCR controls that are achieving a seasonal NO_X average emissions rate of 0.08 lb/mmBtu (or less), which is the seasonal NO_X emissions rate that the EPA has determined is indicative of optimized SCR performance by units with existing SCR controls.

As noted previously, the daily average emissions rate provisions are proposed to apply beginning in the 2024 control period for large coal-fired units with installed SCR controls, one control period later than optimization of those controls would be reflected in the state emissions budgets under the proposal. Likewise, the daily average emissions rate provisions are proposed to apply beginning in the 2027 control period for other large coal-fired units, one control period later than emissions reductions consistent with the installation and operation of SCR controls for such units would be reflected in the state emissions budgets under the proposal. With respect to the units with existing SCR controls, not applying the daily average rate provisions until 2024 would serve two purposes. First, it would provide all the units with a preparatory interval to focus attention on improving not only the average performance of their SCR controls but also the day-to-day consistency of performance before they would be held to increased allowance-surrender consequences for exceeding the daily rate. Second, it would provide the subset of units that exhaust to common stacks with other units that currently lack SCR controls an opportunity to exercise the option to install and certify any additional monitoring systems needed to monitor the individual units' NO_X emissions rates separately; otherwise, the daily emissions rate provisions would apply to the SCR-equipped units based on the combined

[256] EPA–HQ–OAR–2020–0272–0094.

[257] While the proposed design of the daily emissions rate provision would not deter another theoretical type of poor emissions control behavior—*i.e.,* turning off emissions controls at times of peak electricity demand in order to sell the additional electricity that otherwise would have been used to run the control equipment—EPA's analysis of hourly emissions data does not show that this behavior is actually occurring. The data actually suggest the opposite—that emissions controls are generally operated better on peak demand days than on other days. *See* the Ozone Policy Analysis Proposed Rule TSD for additional details about the assessment of the tons and the Discussion of Short-term Emissions Limit document for an assessment of control operation on peak demand days.

NO_X emissions rates measured in the common stacks.[258]

With respect to the units without existing SCR controls, not applying the daily average emissions rate provisions until 2027 would also serve two purposes. First, it would provide a window for plant personnel to gain experience operating any new SCR controls, and second, it would provide some timing flexibility for any individual unit operators who fail to complete SCR control installations before the start of the 2026 control period. With respect to both sets of units, the EPA believes that the lag in applicability of one control period is permissible because the emissions budget provisions are the principal provisions intended to drive the emissions reductions required under the proposal, while the daily average emissions rate provisions are included only to backstop those provisions.

The EPA believes that the proposed unit-specific daily emissions rate provisions would strengthen the incentives for individual coal-fired units with SCR controls to operate and optimize performance of the controls. Continuous operation and optimization of post-combustion controls at individual units would help address individual days that prove in real time to be most critical for downwind ozone levels. Better continuous emissions performance by individual units would also help address disparate impacts of pollution on overburdened communities downwind from the units.

The proposed unit-specific target daily emissions rates are discussed further in Section VII.B.7 of this proposed rule.

ii. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

The second of the proposed trading program enhancements intended to improve emissions performance at the level of individual units is the addition of unit-specific secondary emissions limitations. The secondary emissions limitations would be determined on a unit-specific basis according to each unit's individual performance but would apply to a given unit only under the circumstance where a state's assurance level for a control period has been exceeded, the unit is included in a group of units to which responsibility for the exceedance has been apportioned under the program's assurance provisions, and the unit operated during at least 10% of the hours in the control period. Where these conditions for application of a secondary emissions limitation to a given unit for a given control period are met, the unit's secondary emissions limitation would consist of a prohibition on NO_X emissions during the control period that exceed by more than 50 tons the NO_X emissions that would have resulted if the unit had achieved an average emissions rate for the control period equal to the higher of 0.10 lb/mmBtu or 125 percent of the unit's lowest average emissions rate for any previous control period under any CSAPR seasonal NO_X trading program during which the unit operated for at least 10 percent of the hours.

The proposed secondary emissions limitation would be in addition to, not in lieu of, the primary emissions limitation applicable to each source, which would continue to take the form of a requirement to surrender a quantity of allowances based on the source's emissions, and also in addition to the existing assurance provisions, which similarly would continue to take the form of a requirement for the owners and operators of some sources to surrender additional allowances when a state's assurance level is exceeded. In contrast to these other requirements, the proposed unit-specific secondary emissions limitation would take the form of a prohibition on emissions over a specified level, such that any emissions by a unit exceeding its secondary emissions limitation would be subject to potential administrative or judicial action and subject to penalties and other forms of relief under the CAA's enforcement authorities. The reason for proposing this form of limitation is that experience under the existing CSAPR trading programs has shown that, in some circumstances, the existing assurance provisions have been insufficient to prevent exceedances of a state's assurance level for a control period even when the likelihood of an exceedance has been foreseeable and the exceedance could have been readily avoided if certain units had operated with emissions rates closer to the lower emissions rates achieved in past control periods. The assurance levels exist to ensure that emissions from each state that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state are prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–908 (D.C. Cir. 2008). EPA's programs to eliminate significant contribution must therefore achieve this prohibition, and the new evidence of exceedances of the assurance provisions demonstrate that EPA's existing approach may not be sufficient to accomplish this statutory mandate.

The purpose of including assurance levels higher than the state emissions budgets in the CSAPR trading programs is to provide flexibility to accommodate operational variability attributable to factors that are largely outside of an individual owner's or operator's control, not to allow owners and operators to plan to emit at emissions rates that could be anticipated to cause a state's total emissions to exceed the state's emissions budget or assurance level. Conduct leading to a foreseeable, readily avoidable exceedance of a state's assurance level cannot be reconciled with the statutory mandate of the CAA's good neighbor provision that emissions ''within the state'' significantly contributing to nonattainment or interfering with maintenance of a NAAQS in another state must be prohibited. Because the current CSAPR regulations do not expressly prohibit such conduct and have proven insufficient to deter it in some circumstances, the EPA is proposing to correct the regulatory deficiency in the Group 3 trading program by adding secondary emissions limitations that cannot be complied with through the use of allowances.

The EPA notes that although the principal purpose of the proposed secondary emissions limitations is to strengthen the assurance provisions, which apply on a statewide, seasonal basis, the unit-specific structure of the new limitations would strengthen the incentives for individual units to maintain their emissions performance at levels consistent with their previously demonstrated capabilities. For units with existing post-combustion emissions controls, the new limitations would strengthen the incentives to operate and optimize the controls continuously, and for units without such existing controls, the new limitations would strengthen the incentives to minimize NO_X emissions rates through other possible measures such as improved maintenance and optimization of combustion parameters. Continuous operation of post-combustion controls and greater attention to the combustion process at individual units can be expected to reduce some individual units' emissions rates throughout the ozone season, including on the days that turn out to be most critical for downwind ozone

[258] Based on the information reported by sources to the EPA in their monitoring plans under 40 CFR part 75, five plants subject to this proposal have SCR-equipped and non-SCR-equipped coal-fired EGUs that exhaust together to common stacks: The Clifty Creek plant in Indiana; the Cooper, Ghent, and Shawnee plants in Kentucky; and the Sammis plant in Ohio.

levels. Better emissions performance on average across the ozone season by individual units would also help address disparate impacts of pollution on overburdened communities downwind from some such units.

The proposed unit-specific secondary emissions limitations are discussed further in Section VII.B.8 of this proposed rule.

2. Expansion of Geographic Scope

As part of the proposed approach for implementing the NO_X emissions reductions from EGUs identified as necessary to address various states' obligations under the good neighbor provision with respect to the 2015 ozone NAAQS, the EPA is proposing to expand the existing geographic scope of the existing CSAPR NO_X Ozone Season Group 3 Trading Program to encompass the additional states (and Indian country within the borders of such states) found to have such obligations with respect to EGUs. Specifically, the EPA is proposing to expand the Group 3 trading program to include the following states and Indian country within the borders of the states: Alabama, Arkansas, Delaware, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Tennessee, Texas, Utah, Wisconsin, and Wyoming. Any unit located in a newly added jurisdiction that meets the existing applicability criteria for the Group 3 trading program would become an affected unit under the program, as discussed in Section VII.B.3 of this proposed rule.

CSAPR, the CSAPR Update, and the Revised CSAPR Update also applied to sources in Indian country, although, when those rules were issued, no existing EGUs within the regions covered by the rules were located on lands that the EPA understood at the time to be Indian country.[259] In contrast, within the proposed geographic scope of this rulemaking, the EPA is aware of areas of Indian country within the borders of both Utah and Oklahoma with existing EGUs that would meet the program's applicability criteria. Issues related to state, tribal, and federal jurisdiction with respect to sources in Indian country in general and in these areas in particular are discussed in Section IV.C.2 of this proposed rule.

EPA's proposed approach for determining a portion of each state's budget for each control period that would be set aside for allocation to any units in areas of Indian country within the state not subject to the state's CAA implementation planning authority is discussed in Section VII.B.9 of this proposed rule.

Units in each state would join the Group 3 trading program on one of two possible dates during the program's 2023 control period (that is, the period from May 1, 2023, through September 30, 2023). The reason that two entry dates are possible is that, as discussed in Section VII.B.11 of this proposed rule, the effective date of a final rule in this rulemaking may fall after May 1, 2023. In the case of states (and Indian country within the states' borders) whose sources do not currently participate in the CSAPR NO_X Ozone Season Group 2 trading program—Delaware, Minnesota, Nevada, Utah, and Wyoming—EPA proposes that the sources would begin participating in the Group 3 trading program on the later of May 1, 2023, or the final rule's effective date. However, in the case of the states (and Indian country within the states' borders) whose sources do currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—EPA proposes that the sources would begin participating in the Group 3 trading program on May 1, 2023, regardless of the final rule's effective date, subject to transitional provisions designed to ensure that the increased stringency of the Group 3 trading program as revised in this rulemaking would not substantively affect the sources' requirements prior to the rule's effective date. This approach provides a simpler transition for the sources currently covered by the Group 2 trading program than the alternative approach of being required to switch from the Group 2 trading program to the Group 3 trading program in the middle of a control period, and it is the same approach that was followed for sources that transitioned from the Group 2 trading program to the Group 3 trading program in 2021 under the Revised CSAPR Update. Section VII.B.11 of this proposed rule contains further discussion of the rationale for this approach and the specific proposed transitional provisions.

The EPA notes that under the proposed rule, the expanded Group 3 trading program would include not only the 22 states for which the EPA is proposing to determine that the required control stringency includes, among other measures, installation of new post-combustion controls, but also the three states—Alabama, Delaware, and Tennessee—for which the EPA is proposing to determine that the required control stringency does not include such measures. In previous rulemakings, the EPA has chosen to combine states in a single multi-state trading program only where the selected control stringencies were comparable, in order to ensure that states did not effectively shift their emissions reduction requirements to other states with less stringent emissions reduction requirements by using net out-of-state purchased allowances. Although the assurance provisions in the CSAPR trading programs were designed to address the same general concern about excessive shifting of emissions reduction activities between states, EPA chose not to rely on the assurance provisions as sufficient to allow for interstate trading in situations where the states were assigned differing emissions control stringencies.

In this rulemaking, the EPA believes the previous concern about the possibility that certain states might not make the required emissions reductions is sufficiently addressed through the various proposed enhancements to the design of the trading program, even where states have been assigned differing emissions control stringencies. First, the existing assurance provisions would be substantially strengthened through the addition of the unit-specific secondary emissions limitations discussed in Sections VII.B.1.c.ii and VII.B.8 of this proposed rule. Second, by ensuring that individual units operate their emissions controls effectively, the unit-specific backstop daily emissions rate provisions discussed in Sections VII.B.1.c.i and VII.B.7 of this proposed rule would necessarily also ensure that required emissions reductions occur within the state. With these enhancements to the design of the trading program, the EPA does not believe it would be necessary for sources in Alabama, Delaware, and Tennessee to be excluded from the revised Group 3 trading program simply because their emissions budgets would reflect a different selected emissions control stringency than the other states in the program.

The EPA requests comment on the proposed expansion of the geographic scope of the Group 3 trading program to include the states and areas of Indian country identified above. The EPA also requests comment on the proposed timing under which the two sets of states and Indian country within the

[259] CSAPR and the CSAPR Update both applied to EGUs located in areas within Oklahoma's borders that are now understood to be Indian country, consistent with the U.S. Supreme Court's decision in *McGirt* v. *Oklahoma,* 140 S. Ct. 2452 (2020) (and subsequent case law), clarifying the extent of certain Indian country within Oklahoma's borders. However, those rules were issued before the *McGirt* decision. *See* Section IV.C.2.a.

respective states' borders would be added to the program.

3. Applicability and Tentative Identification of Newly Affected Units

The Group 3 trading program generally applies to any stationary, fossil-fuel-fired boiler or stationary, fossil fuel-fired combustion turbine located in a covered state (or Indian country within the borders of a covered state) and serving at any time on or after January 1, 2005, a generator with nameplate capacity exceeding 25 MW and producing electricity for sale, with exemptions for certain cogeneration units and certain solid waste incineration units. To qualify for an exemption as a cogeneration unit, an otherwise-affected unit generally (1) must be designed to produce electricity and useful thermal energy through the sequential use of energy, (2) must convert energy inputs to energy outputs with efficiency exceeding specified minimum levels, and (3) may not produce electricity for sale in amounts above specified thresholds. To qualify for an exemption as a solid waste incineration unit, an otherwise-affected unit generally (1) must meet the CAA section 129(g)(1) definition of a ''solid waste incineration unit'' and (2) may not consume fossil fuel in amounts above specified thresholds. The complete text of the Group 3 trading program's applicability provisions and the associated definitions can be found at 40 CFR 97.1004 and 97.1002, respectively.

The EPA is not proposing in this rulemaking to revise the existing applicability provisions for the Group 3 trading program. Thus, any unit that is located in a newly added state and that meets the existing applicability criteria for the Group 3 trading program would become an affected unit under the program. The fact that the applicability criteria for all of the CSAPR trading programs are identical therefore is sufficient to establish that any units that are currently required to participate in another CSAPR trading program in any of the proposed additional states where such other programs currently are in effect—Alabama, Arkansas, Minnesota, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin (including Indian country within the borders of such states)—would also become subject to the Group 3 trading program.

In the proposed additional states where other CSAPR trading programs are not currently in effect—Delaware, Nevada, Utah, and Wyoming (including Indian country within the borders of such states)—units already subject to the Acid Rain Program generally would also meet the applicability criteria for the Group 3 trading program, especially if the units are not capable of producing both electricity and useful thermal energy. Based on a preliminary screening analysis of the units in these states that currently report emissions and operating data to the EPA under the Acid Rain Program and that do not report the capability to produce both electricity and useful thermal energy, the Agency believes that all such units are likely to meet the applicability criteria for the Group 3 trading program.

Because the applicability criteria for the Acid Rain Program and the Group 3 trading program are not identical, it is possible that some units could meet the applicability criteria for one program but not the other. Using data reported to the U.S. Energy Information Administration, the EPA has identified 10 sources in Delaware, Nevada, Utah, and Wyoming (and Indian country within the borders of the states) with 27 units that appear to meet the general applicability criteria for the Group 3 trading program and that either (1) do not currently report NO_X emissions and operating data to the EPA under the Acid Rain Program or (2) currently report NO_X emissions and operating data to the EPA under the Acid Rain Program and also report the capability to produce both electricity and useful thermal energy. These units are listed in Table VII.B.3–1 of this proposed rule. For each of these units, the table shows the estimated historical heat input and emissions data that the EPA proposes to use for the unit when determining state emissions budgets if the unit is ultimately treated as subject to the Group 3 trading program.[260] The EPA currently lacks sufficient information to determine whether any of the units listed in the table meets all of the relevant criteria to qualify for an exemption from the Group 3 trading program as a cogeneration unit or a solid waste incineration unit.

TABLE VII.B.3–1—SELECTED EXISTING UNITS THAT COULD BE AFFECTED UNDER PROPOSAL

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Delaware	591	Christiana	11	CT	1,974	0.2594	1
Delaware	591	Christiana	14	CT	1,816	0.2027	1
Delaware	52193	Delaware City Refinery	DCPP2	Boiler	872,824	0.0176	2
Delaware	52193	Delaware City Refinery	DCPP3	Boiler	2,380,430	0.0169	2
Delaware	52193	Delaware City Refinery	DCPP4	Boiler	1,374,817	0.0438	2, 3
Delaware	52193	Delaware City Refinery	MECCU1	CT	1,679,396	0.0070	2
Delaware	52193	Delaware City Refinery	MECCU2	CT	1,679,396	0.0062	2
Delaware	7153	Hay Road	1	CT	1,354,272	0.0685	1
Delaware	7153	Hay Road	2	CT	1,311,286	0.0663	1
Nevada	2322	Clark	GT4	CT	190,985	0.0475	....
Nevada	2322	Clark	GT5	CT	1,455,741	0.0191	....
Nevada	2322	Clark	GT6	CT	1,455,741	0.0187	....
Nevada	2322	Clark	GT7	CT	1,455,741	0.0178	....
Nevada	2322	Clark	GT8	CT	1,455,741	0.0204	....
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val.	GTA	CT	660,100	0.0377	2, 4

[260] As discussed in Section VII.B.10.b of this proposed rule, the EPA expects that any unit that becomes subject to the Group 3 trading program pursuant to a final rule in this rulemaking and that does not already report emissions data to the EPA in accordance with 40 CFR part 75 would not be required to report emissions data or be subject to allowance holding requirements under the Group 3 trading program until May 1, 2024, because of the minimum time interval allowed for installation and certification of the required monitoring systems. Such a unit would not be taken into account for purposes of determining state emissions budgets and unit-level allocations under the Group 3 trading program until the 2024 control period. As indicated in the notes to Table VII.B.3–1 of this proposed rule, six of the listed units have reported to the Energy Information Administration that they plan to retire in 2023.

TABLE VII.B.3–1—SELECTED EXISTING UNITS THAT COULD BE AFFECTED UNDER PROPOSAL—Continued

State	Facility ID	Facility name	Unit ID	Unit type	Estimated ozone season heat input (mmBtu)	Estimated ozone season average NO_X emissions rate (lb/mmBtu)	Notes
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val.	GTB	CT	660,100	0.0387	2, 4
Nevada	54350	Nev. Cogen. Assoc. 1—Garnet Val.	GTC	CT	660,100	0.0387	2, 4
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn.	GTA	CT	749,778	0.0323	2, 4
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn.	GTB	CT	749,778	0.0370	2, 4
Nevada	54349	Nev. Cogen. Assoc. 2—Black Mtn.	GTC	CT	749,778	0.0364	2, 4
Nevada	56405	Nevada Solar One	HI	Boiler	479,452	0.1667	
Nevada	54271	Saguaro	CTG1	CT	1,383,149	0.0314	2
Nevada	54271	Saguaro	CTG2	CT	1,383,149	0.0301	2
Utah	50951	Sunnyside	1	Boiler	1,888,174	0.1715	
Wyoming	56312	Shute Creek	021A	CT	1,000,050	0.0081	2
Wyoming	56312	Shute Creek	021B	CT	1,000,050	0.0093	2
Wyoming	56312	Shute Creek	021C	CT	1,000,050	0.0084	2

Table notes:
[1] Unit already reports NO_X emissions and heat input data to the EPA under 40 CFR part 75 to comply with SIP requirements.
[2] Unit reports capability of producing both electricity and useful thermal energy.
[3] Unit already reports NO_X emissions and heat input data to EPA under 40 CFR part 75 for the Acid Rain Program.
[4] Unit has reported a planned retirement date of March 2023 to the Energy Information Administration.

The EPA requests comment on which existing units in Delaware, Nevada, Utah, and Wyoming and Indian country within the borders of such states would or would not meet the applicability criteria for the Group 3 trading program. In addition, with respect to each of the units listed in Table VII.B.3–1 of this proposed rule, the EPA requests comment, with supporting data, on whether the unit would or would not meet all relevant criteria set forth in 40 CFR 97.1004 and the associated definitions in 97.1002 to qualify for an exemption from the trading program as a cogeneration unit or a solid waste incineration unit (however, see Section VI.B.3 of this proposed rule). The EPA also requests comment, with supporting data, on whether the estimated historical heat input and emissions data identified for the units in Table VII.B.3–1 of this proposed rule are representative for the respective units.

4. New and Revised State Emissions Budgets

The EPA is quantifying budgets or budget formulas specific to each year to ensure that EGUs continue to be incentivized to implement the full extent of EPA's selected control stringency for future control periods. By doing so, the EPA is accounting for both scheduled and not-yet-scheduled fleet turnover in future years. For instance, if State X's budget was 5,000 tons in 2023 but there are 100 tons of emissions from a unit scheduled to retire at the end of that year and 50 tons expected from a new unit coming online by the following year, then the state emissions budget for 2024 will reflect these scheduled changes by establishing a budget of 5,000 tons − 100 tons + 50 tons = 4,950 tons for the subsequent year.

In the Revised CSAPR Update, the EPA included announced fleet changes in state emissions budgets. Several commenters applauded the merit of this approach and the importance of establishing emissions budgets that were robust to an evolving fleet while noting that ''fleet composition is changing constantly and can be exceedingly difficult to project'' leading to overstated emissions budgets to the extent that future retirements were not announced at the time of rule promulgation. Commenters added that ''to address this problem and prevent future unknown retirements from exacerbating this issue, the final rule should include a provision to make additional adjustments to the NO_X budgets based on newly discovered fleet changes.''[261] Commenters were suggesting a dynamic budget approach where the mitigation measures and control stringencies that constituted removal of significant contribution would be identified in a final rule, but the future year state budgets would be dynamic as the EPA applied those stringency assumptions to future year fleet composition data as it became available. While the stringency (reflected by assumed emissions rate for a mitigation technology), would be constant, the fleet composition (reflected by unit heat input) is dynamic. Multiplying the assumed emissions rate for each unit by the heat input for each unit and summing the results to the state level would provide a given year's state emissions budget, and thus under this approach the state emissions budgets would be dynamic as well.

The EPA is proposing a dynamic budget approach in this rule, where emissions budgets starting in the 2025 control period and beyond will be determined through ministerial actions subsequent to this rule's promulgation and based upon the formula described in this rule. This rule will determine the mitigation strategies, respective emissions rates, and formulas and methodologies to be applied to future year data, with which the EPA will perform ministerial actions to calculate emissions budgets for control periods in 2025 and each year thereafter. (Such actions will be publicly announced through notices of data availability (NODAs), similar to how other periodic ministerial actions to implement the trading programs are currently handled. And as with such other actions, interested parties will have the opportunity to seek corrections or administrative adjudication under 40 CFR part 78 if they believe any data used in making these calculations, or the calculations themselves, are in error.) In this manner, the state emissions budgets ultimately implemented for each such future control period will be a product of the data and formula promulgated in this

[261] EPA–HQ–OAR–2020–0272–0094.

action applied to future year reported data that is closer to that future control period and therefore more representative of the fleet for that future control period. As such, the budgets will more accurately reflect power sector composition in that future year and will therefore better achieve the desired environmental outcome over time.

For instance, 2025 budgets will be identified by May 1, 2024, using the latest available reported operational data at that time (2023 heat input data and fleet inventory) along with the formulas and emissions rates quantified in this rule. Therefore, if a unit retires in early 2023 but had not announced its upcoming retirement at the time of rule finalization, the dynamic budget approach would ensure that the budgets for future control periods starting in 2025 would reflect the identified control stringency applied to a fleet that reflects that retirement. If the EPA took an alternative approach of computing the 2025 budget with available data at the time final rule analysis was being conducted, this retirement would likely not be captured in the 2025 state emissions budget, which would lead to a budget that did not fully reflect the application of the identified control stringency. This approach has the advantage of mitigating uncertainty regarding future retirements, new builds, and existing fleet operational/dispatch changes in response to EGU inventory changes.

The example below illustrates the effectiveness of the dynamic budget. In the preset budget approach for 2026, the 2026 heat input is estimated based on the latest available heat input data at the time of rule promulgation (*e.g.,* 2021), which cannot reflect a subsequent fleet change in heat input values (column 2) due to an unanticipated retirement of one of the state's coal-fired units in late 2023. However, the dynamic budget would use 2024 heat input values as opposed to the 2021 heat input values as the latest representative values to inform the 2026 state emissions budget. Therefore, the heat input values in column 2 under the dynamic scenario reflect the change in fleet composition, and when multiplied by the relevant identified control stringency (to be identified when this rule is finalized), the corresponding tonnage (15,000 tons) summed in column 4 constitutes a state budget that better reflects the identified control stringency applied to the fleet composition for that year as opposed to the 17,000 tons in summed in the first table. As illustrated in the example, the dynamic variable is the heat input variable which changes over time to reflect the most representative EGU fleet.

	Preset Budget Appraoch (2026)			Dynamic Budget Approach (2026)		
	Preset Heat Input (tBtu)	Preset Emissions Rate (lb/mmBtu)	Preset Tons (Heat input X Emissions Rate)/2000	Updated Heat Input (tBtu)	Emissions Rate (lb/mmBtu)	Updated Tons (Heat Input X Emissions Rate)/2000
Coal Units	600	0.05	15,000	500	0.05	12,500
Gas Units	400	0.01	2,000	500	0.01	2,500
State Budget (tons)			**17,000**			**15,000**

The EPA requests comment on this dynamic budget approach, including the methodology, the start year, and the impacts.

With regard to the state emissions budgets for the 2023 and 2024 control periods promulgated in this rule, the EPA is using the best available data at the time of the proposed rule regarding retirements and new builds. The EPA relies on a compilation of data from DOE EIA Form 860 (where facilities report their future retirement plans) and information included in the Agency's NEEDS database. This information is considered to be highly reliable, real-world information that provides the EPA with high confidence that such retirements will in fact occur. EPA plans to update this data on retirements and new builds at final rule using the latest information available from these sources at that time as well as input provided by commenter.

EPA's emissions budget methodology and formula for establishing Group 3 budgets are described in detail in the Ozone Transport Policy Analysis Proposed Rule TSD and summarized below.

a. Methodology for Determining Preset State Emissions Budgets for the 2023 and 2024 Control Periods

For determining state emissions budgets, the EPA generally uses historical ozone season data from the 2021 ozone season, the most recent data and therefore the most representative of near-term fleet conditions. This is similar to the approach taken in the CSAPR Update where the EPA began with 2015 data (the most recent year at the time). As in the CSAPR Update, the EPA combined historical data with IPM data to determine emissions budgets as follows:

(1) Determine a future year baseline—Start with the latest reported historical unit-level data (*e.g.,* 2021), and adjust any unit data where a retirement, a new build, a coal-to-gas conversion, or a SCR retrofit is known to occur by the baseline year. This results in a future year (*e.g.,* 2023) baseline for emissions budget purposes.

(2) Factor in additional emissions controls for the selected control stringency for the given state in the given year—For the unit-level emissions control technologies identified in this control stringency, adjust the baseline unit-level emissions and emissions rates. For example, if an SCR-controlled coal unit had a baseline emissions rate greater than 0.08 lb/mmBtu, its emissions rate and corresponding emissions would be adjusted down to levels reflecting its operation at 0.08 lb/mmBtu.

(3) Incorporate generation shifting—Use IPM in a relative way to capture the reductions expected from generation shifting (constrained to within each state) at the representative dollar per ton level corresponding to the selected control stringency.

By using historical unit and state-level NO_X emissions rates, heat input, and emissions data in the first stage of budget setting process outlined above, the EPA is grounding its budgets in the most recent representative historical operation for the covered units.[262] This dataset is a reasonable starting point for

[262] The EPA notes that historical state-level ozone season EGU NO_X emissions rates are publicly available and quality assured data. They are monitored using CEMS or other methodologies allowed for use by qualifying units under 40 CFR part 75 and are reported to the EPA directly by power sector sources.

the budget-setting process as it reflects the latest data reported by affected facilities under 40 CFR part 75. The reporting requirements include quality control measures, verification measures, and instrumentation to best record and report the data. In addition, the designated representatives of EGU sources are required to attest to the accuracy and completeness of the data. The EPA adjusted the 2021 ozone-season data to reflect committed fleet changes under a baseline scenario (*i.e.,* announced and confirmed retirements, new builds, and retrofits that have already occurred). For example, if a unit emitted in 2021, but retired in 2022, its 2021 emissions would not be included in the 2023 baseline estimate. For units that had no known changes, the 2023 baseline emissions assumption was the actual reported data from 2021. The EPA also included known new units and scheduled retrofits in this manner. Using this method, the EPA arrived at a baseline emission, heat input, and emissions rate estimate for each unit for a future year (*e.g.,* 2023), and then was able to aggregate those unit-level estimates to state-level totals. These state-level totals constituted the state's baseline from an engineering analytics perspective. The ozone-season state-level emissions, heat input, and emissions rates for covered sources under a baseline scenario were determined for each future year examined that receives a preset budget under this proposed rule (2023 and 2024).

The EPA then examined how the baseline emissions and emissions rates would change under different control stringencies for EGUs. For instance, under the SCR optimization scenario, if a unit was not operating its SCR at 0.08 lb/mmBtu or lower in the baseline, the EPA lowered that unit's assumed emissions rate to 0.08 lb/mmBtu and calculated the impact on the unit's and state's emissions rate and emissions. Note that the heat input is held constant for the unit in the process, reflecting the same level of unit operation compared to historical 2021 data. An improved emissions rate is then applied to this heat input, reflecting control optimization. In this manner, the state-level baseline totals reflecting known changes were adjusted to reflect the additional application of the assumed control technology at a given control stringency.

Finally, the EPA used IPM to capture any generation shifting at a given control stringency necessary for the majority of the respective emissions control technology to operate. The EPA explains how it accounts for generation shifting in more detail in Section VI.B of this proposed rule and in the Ozone Transport Policy Analysis Proposed Rule TSD. In this rule, as a proxy for the near-term reductions required in 2023 and 2024, the EPA has constrained generation shifting to occur only within-state. The EPA also estimates emissions reductions associated with generation shifting in 2025 and 2026 for purposes of the illustrative state budgets, but as explained below, the dynamic budget process to determine budgets for those years will incorporate emissions reductions attributable to generation shifting through the inclusion of newly reported unit-level data from the future compliance periods.

b. Methodology for Determining Dynamic State Emissions Budgets for Control Periods in 2025 Onwards

The methodology for determining state emissions budgets for later control periods (2025 and beyond) is nearly identical to the process for quantifying preset budgets in 2023 and 2024 described earlier; it is just applied at a later date and applied to the most recent representative operational available at that time. The EPA will issue by ministerial action these dynamic budget quantifications approximately 1 year before the relevant control period. For instance, starting in early 2024, the EPA would take the most recent 2023 ozone season data, calculate 2025 state emissions budgets using the methodology below and update its unit-level and state-level state emissions budget files that will be released when this rule is finalized (and for which the EPA has included in this proposed rule current examples for public comment). By March 1 of 2024, and each year thereafter, the EPA would make publicly available (in manner similar to data and preliminary computations for allocations from new unit set-asides) the preliminary state emissions budgets and unit-level allocations for the subsequent control period (*e.g.,* 2025) and would provide stakeholders with a 30-day opportunity to submit any objections to the updated data and computations. By May 1 of 2024, and each year thereafter, the EPA would issue the final budgets and allowance allocations for the next control period (*e.g.,* 2025).

The differences to each of the formula steps to calculate dynamic budgets for control periods in 2025 and beyond, relative to the calculation of preset budgets for the 2023 and 2024 control periods, are described later:

(1) Determine a future year baseline—At this step, the EPA would start with the latest reported historical unit-level heat input data available at that time (*e.g.,* for 2025 state emissions budgets, the EPA would use the newly available 2023 heat input data rather than 2021 heat input data). Doing so would capture the latest operational data reflecting new builds and retirements. This would yield a future year (*e.g.,* 2025) baseline for emissions budget purposes.

(2) Factor in additional emissions controls for the selected control stringency for the given state in the given year—For the unit-level emissions reduction measures identified in the selected control stringency, adjust the baseline unit-level emissions and emissions rates. This step would be nearly the same for control periods in 2025 and beyond as for the 2023 and 2024 control periods, the only difference being that as described in Section VI.D of this proposed rule, for each control period from 2026 onward, the unit-specific emissions rates assumed for all affected states except Alabama, Delaware, and Tennessee will reflect the selected control stringency that incorporates post-combustion control retrofit opportunities for the relevant units identified in the state emissions budgets and calculations appendix to the Ozone Transport Policy Analysis Proposed Rule TSD. These rates would be defined in this rule and would not change subsequently. They would not be applied until 2026, based on the time necessary to install these mitigation technologies as discussed in Sections VI.B, VI.C, and VII.A of this proposed rule.

(3) Incorporate generation shifting—This step would be automatically captured in dynamic budget calculations as generation shifting in a compliance scenario would no longer have to be projected by IPM and incorporated into the state budgets through an additional calculation. Instead, it would be embodied in the newly reported heat input data described above and that is used to determine the dynamic budgets.

Additional details, corresponding data and formulas, and examples for the dynamic budget are described in the Ozone Transport Policy Analysis Proposed Rule TSD.

c. Proposed and Illustrative State Emissions Budgets

For each covered state (and Indian country within the state's borders), preset budgets are established for the two individual control periods 2023 and 2024. For 2025 and beyond, the dynamic budget formula promulgated in this proposed rule would be applied to future year data to quantify state emissions budgets for those control periods. The proposed default procedures for allocating the allowances from each state budget among the units in each state (and Indian country within the state's borders) are described in Section VII.B.9 of this proposed rule. The amounts of the proposed state emissions budgets for the 2023 and 2024 control periods are shown in Table VII.B.4.c–1. Table VII.B.4.c–2 shows illustrative state emissions budgets for the 2025 and 2026 control periods derived by applying the identified control stringency to the most recent historical data, but these budgets are only illustrative because, under the proposal, the implemented state emissions budgets for these years will be determined at a future date through application of the proposed budget-setting methodology to data that reflect the emissions control stringencies finalized in the rulemaking combined with the latest available data on the composition and utilization of the EGU fleet.

TABLE VII.B.4.C–1—PROPOSED CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR THE 2023 AND 2024 CONTROL PERIODS [a b]

State	Proposed emissions budgets for 2023 control period (tons)	Proposed emissions budgets for 2024 control period (tons)
Alabama	6,364	6,306
Arkansas	8,889	8,889
Delaware	384	434
Illinois	7,364	7,463
Indiana	11,151	9,391
Kentucky	11,640	11,640
Louisiana	9,312	9,312
Maryland	1,187	1,187
Michigan	10,718	10,718
Minnesota	3,921	3,921
Mississippi	5,024	4,400
Missouri	11,857	11,857
Nevada	2,280	2,372
New Jersey	799	799
New York	3,763	3,763
Ohio	8,369	8,369
Oklahoma	10,265	9,573
Pennsylvania	8,855	8,855
Tennessee	4,234	4,234
Texas	38,284	38,284
Utah	14,981	15,146
Virginia	3,090	2,814
West Virginia	12,478	12,478
Wisconsin	5,963	5,057
Wyoming	9,125	8,573

Table Notes:

[a] The state emissions budget calculations pertaining to Tables VII.B.4.c–1 and VII.B.4.c–2 are described in greater detail in the Ozone Transport Policy Analysis Proposed Rule TSD. Budget calculations and underlying data are also available in Appendix A of that TSD.

[b] In the event a final rule in this rulemaking becomes effective after May 1, 2023, the emissions budgets and assurance levels for the 2023 control period would be adjusted under the rule's proposed transitional provisions to ensure that the increased stringency of the new budgets would apply only after the rule's effective date, even though the revised Group 3 trading program would be implemented for most sources as of the start of the 2023 ozone season on May 1, 2023. The 2023 budget amounts shown in Table VII.B.4.c–1 do not reflect these possible adjustments. The transitional provisions are discussed in Section VII.B.11 of this proposed rule.

TABLE VII.B.4.C–2—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR THE 2025 AND 2026 CONTROL PERIODS

State	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Alabama	6,306	6,306
Arkansas	8,889	3,923
Delaware	434	434
Illinois	7,463	6,115
Indiana	8,714	7,791
Kentucky	11,134	7,573
Louisiana	9,179	3,752
Maryland	1,187	1,189
Michigan	10,759	6,114
Minnesota	3,910	2,536
Mississippi	4,400	1,914
Missouri	10,456	7,246
Nevada	2,372	1,211
New Jersey	799	799
New York	3,763	3,238
Ohio	8,369	8,586
Oklahoma	9,393	4,275
Pennsylvania	8,855	6,819
Tennessee	4,008	4,008

TABLE VII.B.4.c–2—ILLUSTRATIVE CSAPR NO_X OZONE SEASON GROUP 3 STATE EMISSIONS BUDGETS FOR THE 2025 AND 2026 CONTROL PERIODS—Continued

State	Illustrative emissions budgets for 2025 control period (tons)	Illustrative emissions budgets for 2026 control period (tons)
Texas	36,619	21,946
Utah	15,146	2,620
Virginia	2,948	2,567
West Virginia	12,478	10,597
Wisconsin	4,198	3,473
Wyoming	8,573	4,490

5. Variability Limits and Assurance Levels

Like each of the other CSAPR trading programs, the Group 3 trading program currently includes assurance provisions designed to limit the total emissions from the sources in each state (and Indian country within the state's borders) in each control period to an amount close to the state's emissions budget for the control period, consistent with the good neighbor provision's requirement that required emissions reductions must be achieved within the state, while allowing some flexibility beyond the emissions budget to accommodate year-to-year operational variability beyond sources' reasonable ability to control. For each state, the assurance provisions establish an assurance level for each control period, defined as the sum of the state's emissions budget for the control period plus a variability limit, which under the existing Group 3 trading program regulations is 21 percent of the relevant state emissions budget. The purpose of the variability limit is to account for year-to-year variability in EGU operations, which can occur for a variety of reasons including changes in weather patterns, changes in electricity demand, and disruptions in electricity supply from other units or from the transmission grid. Because of the need to account for such variability in operations of each state's EGUs, the fact that emissions from the state's EGUs may exceed the state's emissions budget for a given control period is not treated as inconsistent with satisfaction of the state's good neighbor obligations as long as the total emissions from the EGUs remain below the state's assurance level. Emissions from a state's EGUs above the state's emissions budget but below the state's assurance level are treated in the same manner as emissions below the state's emissions budget in that such emissions are subject to the same requirement to surrender allowances at a ratio of one allowance per ton of emissions. In contrast, emissions above the state's assurance level for a given control period are strongly discouraged as inconsistent with the state's good neighbor obligations and are subject to an overall 3-for-1 allowance surrender ratio. The establishment of assurance levels with associated extra allowance surrender requirements was intended to respond to the D.C. Circuit's holding in *North Carolina* requiring the EPA to ensure within the context of an interstate trading program that sources in each state are required to address their good neighbor obligations within the state and may not simply shift those obligations to other states by failing to reduce their own emissions and instead surrendering surplus allowances purchased from sources in other states.[263]

In this rulemaking, the EPA is not proposing to alter the basic structure of the Group 3 trading program's assurance provisions, which would continue to set an assurance level for each control period equal to the state's emissions budget for the control period plus a variability limit and would continue to apply a 3-for-1 surrender ratio to emissions exceeding the state's assurance level.[264] Each assurance level also would continue to apply to the collective emissions of all units within the state and Indian country within the state's borders.[265] For the 2023 and 2024 control periods, the EPA proposes to retain the Revised CSAPR Update's methodology for determining each state's variability limit as 21 percent of the state's emissions budget for the control period, except that because the EPA is proposing to revise the state emissions budgets for these control periods, the EPA proposes to determine the corresponding variability limits as 21 percent of the revised budgets. However, for control periods after 2024, the EPA is proposing a change to the methodology for determining the variability limits. Specifically, the EPA proposes to determine each state's variability limit for the control periods in 2025 or a later year so that, instead of always multiplying the state's emissions budget for the control period by a value of 21 percent, the percentage value used would be the higher of 21 percent or the percentage (if any) by which the total reported heat input of the state's affected EGUs in the control period exceeds the total reported heat input of the state's affected EGUs as reflected in the state's emissions budget for the control period. For example, if the total reported heat input of the state's covered sources for the 2025 control period was 90 percent or 110 percent of the total reported heat input of the state's covered sources for the 2023 control period (*i.e.,* the heat input the EPA would have used in computing the state's 2025 emissions budget), then the state's variability limit for the 2025 control period would be 21 percent of the state's emissions budget, while if the total reported heat input of the state's covered sources for the 2025 control period was 130 percent of the total reported heat input of the state's covered sources for the 2023 control period, then the state's variability limit for the 2025 control period would be 30 percent of the state's emissions budget. The EPA expects that the minimum 21 percent would apply in almost all instances, and that the alternative, higher percentage value would apply only in control periods where operational variability caused an extreme increase relative to the earlier year used in setting the state's emissions budget, which would be a situation

[263] 531 F.3d at 908.

[264] As discussed in Section VII.B.8 of this proposed rule, the EPA is also proposing to establish a new secondary emissions limitation for individual units that would apply in situations where an exceedance of the relevant state's assurance level has occurred.

[265] *See* 40 CFR 97.1002 (definitions of ''common designated representative,'' ''common designated representative's assurance level'' and ''common designated representative's share''), 97.1006(c)(2), and 97.1025.

meriting a temporarily higher variability limit and assurance level.

The purpose of the proposed revision to the variability limits is to better align the variability limits for successive control periods with the regularly updated heat input data that would be used in the proposed process for dynamically setting the state emissions budgets. Under EPA's proposed budget-setting process, each emissions budget would be computed using the latest available reported heat input, which for each budget set for a control period in 2025 or a later year would be the heat input for the control period two years before the control period whose budget is being determined (for example, the state emissions budgets for the 2025 control period would be computed in early 2024 using the reported heat input for the 2023 control period). The proposed revised variability limits would be well coordinated with the budgets established using this dynamic budgeting process, because the percentage change in the actual heat input for the control period relative to the earlier-year heat input used in computing the state's emissions budget would be an appropriate measure of the degree of operational variability actually experienced by the state's EGUs in the control period relative to the assumed operating conditions reflected in the state's budget. Setting a variability limit in this manner would be entirely consistent with the overall purpose of including variability limits in the assurance provisions.

The reason the EPA is proposing to use the higher of a fixed 21% or the percentage change in heat input computed as just described is that the EPA believes that, for operational planning purposes, it can be useful for sources to know in advance of the control period a minimum value for what the variability limit could turn out to be. Because a state's actual total heat input for a control period is not known until after the end of the control period, this proposed revision would have the consequence that the state's final variability limit and assurance level for the control period also would not be known until after the control period. However, because the proposed rule provides that the variability limit would always be at least 21 percent, the sources in a state would be able to rely for planning purposes on the knowledge that the assurance level would always be at least 121 percent of the state's emissions budget for the control period. Advance knowledge of the minimum possible amount of the assurance level can be useful to sources, because one way a source can be confident that it will never incur the 3-for-1 allowance surrender ratio owed for emissions exceeding its state's assurance level is to plan its operations so as to never allow its own emissions to exceed its own share of the state's assurance level for the control period. Knowing that the variability limit would always be at least 21 percent would provide sources with values they could use for such planning purposes.

The EPA believes that 21 percent is a reasonable value to use as the fixed variability limit for the 2023 and 2024 control periods and as the minimum variability limit for the control periods in 2025 and later years. To determine appropriate variability limits for the trading programs established in CSAPR, the EPA analyzed historical state-level heat input variability over the period from 2000 through 2010 as a proxy for emissions variability, assuming constant emissions rates. *See* 76 FR 48265. Based on that analysis, the variability limits for ozone season NO_X in both CSAPR and the CSAPR Update were set at 21 percent of each state's budget, and these variability limits for the NO_X ozone season trading programs were then codified in 40 CFR 97.510 and 40 CFR 97.810, along with the respective state budgets. For the Revised CSAPR Update, the EPA performed an updated variability analysis for the twelve states being moved into the Group 3 trading program in that rulemaking, evaluating historical state-level heat input variability over the period from 2000 through 2019. The updated analysis again resulted in a variability estimate of 21 percent. The EPA also considered shorter time periods for the updated analysis and found that the resulting variability estimates were not especially sensitive to the particular time period analyzed.[266] A further updated analysis for this rulemaking again results in a variability estimate of 21 percent for most states, and although the historical analysis indicates higher percentages for the two states with the smallest total heat input figures in this analysis—Delaware and New Jersey—the EPA does not consider it appropriate to raise the variability limit percentage beyond 21 percent for all other states based on the analytic results for these states, where small absolute heat input figures have resulted in larger variability percentages.[267] Based on the consistent conclusions of these multiple analyses, the EPA proposes to continue using 21 percent as the fixed variability limit percentage for the 2023 and 2024 control periods and as the minimum value in the revised approach for establishing variability limits for the control periods in 2025 and later years.

The EPA requests comment on the proposed rule to set variability limits for the 2023 and 2024 control periods as 21 percent of the respective revised state emissions budgets, consistent with the methodology used to determine the variability limits for these control periods set in the Revised CSAPR Update. In addition, the EPA requests comment on whether to set higher variability limits for Delaware and New Jersey for 2023 and 2024 based on the results of the most recent variability analysis. The EPA also requests comment on the proposed rule to establish a revised methodology for setting variability limits for all states for control periods in 2025 and later years, as discussed in this section.

6. Annual Recalibration of Allowance Bank

As discussed in Section VII.B.1.b of this proposed rule, in this rulemaking, the EPA is proposing two revisions to the Group 3 trading program designed to better maintain the control stringency selected in the final rule in this rulemaking. The first proposed revision, discussed Section VII.B.4 of this proposed rule, is to adopt a dynamic budget-setting methodology that would allow state emissions budgets in future years to reflect more accurate information about the composition and utilization of the EGU fleet. The second, complementary, proposed revision is to recalibrate the bank of unused allowances each control period in order to prevent allowance surpluses in individual control periods from accumulating and adversely impacting the ability of the trading program in future control periods to maintain the selected control stringency identified in the rulemaking as necessary to address states' good neighbor obligations with respect to the 2015 ozone NAAQS.

The EPA proposes to begin the bank recalibration process starting with the 2024 control period, after the compliance process for the 2023 control period for all current and newly added states in the Group 3 trading program

[266] For details on the original variability analysis for 26 states over the 2000–2010 period, including a description of the methodology, see the Power Sector Variability Final Rule TSD from the CSAPR (EPA–HQ–OAR–2009–0491–4454). For the updated variability analysis for twelve states for the 2000–2019 period, *see* the Excel file ''Historical Variability in Heat Input 2000 to 2019.xls.'' Both documents are available in the docket for this proposal.

[267] *See* the Excel document, ''OS Heat Input Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

has been completed. The recalibration process for each control period would be carried out on or shortly after August 1 of that control period, two months after the compliance deadline for the previous control period, making the proposed date of the first recalibration August 1, 2024. The recalibrations could not take place significantly earlier than August 1 each year because compliance for the previous control period would not be completed until after June 1. However, because data on the amounts of allowances held are publicly available and the total quantity of allowances needed for compliance for the previous control period would be known shortly after the end of that control period, sources and other market participants would be able to ascertain with reasonable accuracy shortly after the end of each control period what degree of recalibration to expect for the next control period, even if the recalibration would not actually be carried out until the following August.

Before undertaking a recalibration process each control period, the EPA would first determine whether the total amount of all banked Group 3 allowances from previous control periods held in all facility accounts and general accounts in the Allowance Management System accounts exceeds the target bank amount. (For this purpose, no distinction would be made between banked Group 3 allowances issued from the state emissions budgets for previous control periods and banked Group 3 allowances issued through the conversion of previously banked Group 2 allowances.) If the total amount of banked Group 3 allowances does not exceed the target bank amount, the EPA would not carry out any recalibration for that control period. If the total amount of unused allowances does exceed the target bank amount, the EPA would determine for each account with holdings of banked Group 3 allowances the account-specific recalibrated amount of allowances, computed as the target bank amount multiplied by the account's total holdings of banked Group 3 allowances and divided by the total amount of banked Group 3 allowances in all accounts, rounded up to the nearest allowance. Finally, the EPA would deduct from each account any banked Group 3 allowances exceeding the account's recalibrated amount of banked allowances.

As the target bank amount used in the recalibration process for each control period, the EPA proposes to use an amount determined as 10.5 percent of the sum of the state emissions budgets for the control period, or half of the sum of the states' proposed minimum variability limits. The EPA has two reasons for proposing this amount. First, in the transition from CSAPR to the CSAPR Update, where the EPA set a target bank amount 1.5 times the sum of the variability limits, and in the transition from the CSAPR Update to the Revised CSAPR Update, where the EPA set a target bank amount of 1.0 times the sum of the variability limits, in each case the initial bank proved larger than necessary, as total emissions of all sources in the program were less than the budgets. Second, an analysis of year-to-year variability of heat input for the region covered by this proposed rule suggests that the regional heat input for an individual year can be expected to vary by up to 10.5 percent above or below the central trend with 95% confidence. This variability analysis is an application to the entire region of the variability analysis EPA has performed for individual states to establish the variability limit of 21 percent for the states in the trading program.[268] When the analysis is performed at the regional level, the data show less year-to-year variation than when the analysis is performed at the individual state level. Within the trading program structure, it is logical to use variability analyzed at the level of individual states to set the variability limits, which apply at the level of individual states, while using variability analyzed at the level of the overall region to set a target level for a bank, which will apply at the level of the overall program.

The annual bank recalibrations will help maintain the control stringency determined to be necessary to address states' good neighbor obligations for the 2015 ozone NAAQS. Moreover, the proposed recalibrations are less complex than alternative approaches would be. For example, the NO_X Budget Trading Program established in the NO_X SIP Call also contained provisions designed to prevent excessive accumulations of banked allowances on program stringency, but those provisions—under the name ''progressive flow control''—introduced uncertainty as to whether banked allowances would be usable to offset one ton of emissions or less than one ton of emissions in the current control period. The EPA considers the recalibration mechanism proposed here to be simpler with less associated uncertainty.

Finally, the EPA observes that the proposed recalibration mechanism is entirely consistent with the Agency's existing authority under 40 CFR 97.1006(c)(6) to ''terminate or limit the use and duration'' of any Group 3 allowance ''to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' The Administrator proposes to determine that the recalibrations are both necessary and appropriate to ensure that the control stringency selected in this rulemaking is maintained and states' good neighbor obligations with respect to the 2015 ozone NAAQS are addressed.

The EPA requests comment on the proposed bank recalibration provisions and the proposed use of a target bank amount computed as 10.5 percent times the sum of the state emissions budgets for each control period.

7. Unit-Specific Backstop Daily Emissions Rates

While the identified EGU emissions reductions in Section VI of this proposed rule are incentivized and secured primarily through the corresponding seasonal state emissions budgets (expressed as a seasonal tonnage limit for all covered EGUs within a state's borders) described earlier, the EPA is also incorporating backstop daily emissions rates of 0.14 lb/mmBtu for coal-fired steam units serving generators with nameplate capacity greater than or equal to 100 MW in covered states. The backstop emissions rates will first apply in 2024 for coal-fired steam units with existing SCR controls, and in 2027 for coal-fired steam units currently without SCR controls. For a unit that exceeds its applicable backstop daily emissions rate on any day, all emissions on that day exceeding the emissions that would have occurred at the backstop daily emissions rate will be subject to a 3-for-1 allowance surrender ratio instead of the normal 1-for-1 allowance surrender ratio. See Appendix A of the Ozone Transport Policy Proposed Rule TSD for a list of coal-fired steam units serving generators larger than or equal to 100 MW in covered states for which the identified backstop emissions rate would apply starting in either 2024 or 2027.

The EGU NO_X Mitigation Strategies Proposed Rule TSD describes the methodology for deriving the 0.14 lb/mmBtu daily rate limit in more detail. The methodology is summarized as follows. First, consistent with

[268] See the Power Sector Variability Final Rule TSD from CSAPR, available at *https://www.epa.gov/csapr/power-sector-variability-final-rule-tsd for a description of the methodology.* Also see the Excel document ''OS Heat Input—Variability 2000 to 2021.xls'' for updated data, application of the CSAPR variability methodology, and results applied to heat input for 2000 through 2021 for all states and for the region collectively.

stakeholders' focus on providing daily assurance of control operation, EPA determined that daily (as opposed to hourly or monthly) was an appropriate time metric for backstop emissions rate limits instituted to ensure operation of controls on high ozone days. The EPA derived the 0.14 lb/mmBtu daily rate limit by determining the particular level of a daily rate that would be comparable in stringency to the 0.08 lb/mmBtu seasonal emissions rate that the Agency has identified as reflecting SCR optimization at existing units.[269] The EPA first conducted an empirical exercise using reported daily emissions rate data from existing, SCR-controlled coal units that were emitting at or below 0.08 lb/mmBtu on a seasonal average basis. Recognizing that this seasonal rate reflects the average across a unit's range of varying daily rates reflecting different operation conditions, including some occasions when the SCR control may not be operating or may not be fully optimized, the EPA identified the upper end of the daily emissions rate range for these units. When the EPA examined the daily emissions rate pattern for these units considered to be optimizing their SCRs on a seasonal basis, the EPA observed that over 95 percent of the time, their daily rates were below 0.14 lb/mmBtu. In addition, for these units, less than 1 percent of their seasonal emissions would exceed this daily rate limit.

The EPA conducted this analysis to be consistent with the methodology developed in the 2014 1-hr SO_2 attainment area guidance for identifying ''comparably stringent'' emissions rates over varying time-periods.[270] Appendix C of that guidance describes a series of steps that involve: (1) Compiling emissions data to reflect a distribution of emissions rates with various averaging times, (2) determining the 99th percentile of the average emissions values compiled in the previous step, and then (3) applying ''adjustment factors'' or ratios of the 99th percentile values to emissions rates to convert them (usually from a short-term rate to a longer-term rate). In this case, the EPA applied the methodology in reverse to convert a longer-term limit (the seasonal rate of 0.08 lb/mmBtu which was assumed to be equal to a 30-day rate of 0.08 lb/mmBtu) to a comparably stringent short-term limit (a daily rate of 0.14 lb/mmBtu). The EPA requests comment on the proposed incorporation of a backstop daily emissions rate element into the Group 3 trading program and on the proposed methodology for determining the daily emissions rate of 0.14 lb/mmBtu.

In addition, the EPA requests comment on application of the backstop daily emissions rates in the event that an affected unit finds it more economic to retire shortly after the start of the 2027 ozone season in lieu of investing in new NO_X post-combustion control technology. This proposed rule's state emissions budgets would require emissions reductions starting in 2026 commensurate with SCR retrofits at these units regardless of when these unit-level backstop rates are subsequently imposed. The EPA recognizes that such retrofits in practice may be less environmentally efficient compared to imminent retirement that would potentially yield lower cumulative emissions of NO_X and multiple other pollutants over time. The EPA also recognizes that several coal-fired EGUs have been considering retirement by 2028 under compliance pathways available under Clean Water Act effluent guidelines[271] and the coal combustion residuals rule under the Resource Conservation and Recovery Act.[272] 2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas.[273] To facilitate a potentially economic and environmentally superior unit-level compliance response across these programs that nonetheless maintains the NO_X reductions required by the state budgets from 2026 forward in this proposed rule, the EPA is requesting comment on potentially deferring the application of the backstop daily rate for large coal EGUs that submit written attestation to the EPA that they make an enforceable commitment to retire by no later than the end of calendar year 2028. EPA anticipates that units failing to retire contrary to their attestation would become subject to the backstop emissions rate in the 2029 ozone season, and would likely be subject to other appropriate enforcement proposed rule under the Clean Air Act or other relevant authorities.

8. Unit-Specific Emissions Limitations Contingent on Assurance Level Exceedances

As emphasized by the D.C. Circuit in its decision invalidating CAIR, under the CAA's good neighbor provision, emissions ''within the State'' that contribute significantly to nonattainment or interfere with maintenance of a NAAQS in another state must be prohibited. *North Carolina* v. *EPA,* 531 F.3d 896, 906–908 (D.C. Cir. 2008). The CAIR trading programs contained no provisions limiting the degree to which a state could rely on net purchased allowances as a substitute for making in-state emissions reductions, an omission which the court found was inconsistent with the requirements of the good neighbor provision. *Id.* In response to that holding, the EPA established the CSAPR trading programs' assurance provisions to ensure that, in the context of a flexible trading program, the emissions reductions required under the good neighbor provision in fact will take place within the state. The EPA believes the assurance provisions have generally been successful in achieving that objective, as evidenced by the fact that since the assurance provisions took effect in 2017, out of the nearly 300 instances where a given state's compliance with the assurance provisions of a given CSAPR trading program for a given control period has been assessed, a state's collective emissions have exceeded the applicable assurance level only four times.

Unfortunately, the EPA also recognizes that the assurance provisions' very good historical compliance record is not good enough. The four past exceedances all occurred under the Group 2 trading program: Sources in Mississippi collectively exceeded their applicable assurance levels in the 2019 and 2020 control periods, and sources in Missouri collectively exceeded their applicable assurance levels in the 2020 and 2021 control periods.[274] Both of the

[269] *See* page 24 of ''Guidance for 1-hour SO_2 Nonattainment Area SIP Submission'' at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.* ''A limit based on the 30-day average of emissions, for example, at a particular level is likely to be a less stringent limit than a 1-hour limit at the same level 1 since the control level needed to meet a 1-hour limit every hour is likely to be greater than the control level needed to achieve the same limit on a 30-day average basis.''

[270] *See* Guidance for 1-Hour SO_2 Nonattainment Area SIP Submissions available at *https://www.epa.gov/sites/default/files/2016-06/documents/20140423guidance_nonattainment_sip.pdf.*

[271] *See* 40 CFR 423.11(w).

[272] *See* 40 CFR 257.103(b).

[273] *See* 40 CFR 51.308(f).

[274] Information on the assurance level exceedances in the 2019 and 2020 control periods is available in the final notices concerning EPA's administration of the assurance provisions for those control periods. 85 FR 53364 (August 28, 2020); 86 FR 52674 (September 22, 2021). The EPA will publish an analogous final notice for the 2021 control period by October 1, 2022, and will also publish a preliminary notice by August 1, 2022. At this time, information on the relevant Missouri assurance level for the 2021 control period is available at 40 CFR 97.806(c)(2) and 97.810 and preliminary data on Missouri units' emissions of

exceedances by Missouri sources could easily have been avoided if the owner and operator of several SCR-equipped, coal-fired steam units had not chosen to idle the units' controls and rely instead on net out-of-state purchased allowances. The exceedances were large, and ample quantities of allowances to cover the resulting 3-for-1 allowance surrender requirements were purchased in advance, suggesting that the assurance level exceedances may have been anticipated as a possibility. In the case of the Mississippi exceedances, the exceedances were smaller, operational variability (manifesting as increased heat input) appears to have been a material contributing factor, and the EPA has not concluded that the owners and operators anticipated the exceedances. However, an additional contributing factor was the fact that several large, gas-fired steam units without SCR controls emitted NO_X at average rates much higher than the average emissions rates the same units had achieved in previous control periods. In short, while the Missouri exceedances appear far more significant, EPA's analysis indicates that all four past exceedances could have been avoided if the units most responsible had achieved emissions rates more comparable to the same units' previous performance. In EPA's view, the operation of the Missouri units in particular—although not prohibited by the current regulatory requirements—cannot be reconciled with the statutory requirements of the good neighbor provision. The fact that such operation is not prohibited by the current regulations therefore indicates a deficiency in the current regulatory requirements.

To correct the deficiency in the regulatory requirements, the EPA proposes in this rulemaking to revise the Group 3 trading program regulations to establish an additional emissions limitation to more effectively deter avoidable assurance level exceedances. Because the pollutant involved is ozone season NO_X and the particular sources for which deterrence is most needed are located in states that are proposed to transition soon from the Group 2 trading program to the Group 3 trading program, the EPA is proposing to promulgate the strengthening provisions as revisions to the Group 3 trading program regulations rather than the Group 2 trading program regulations.[275]

The two current emissions-related compliance requirements in the Group 3 trading program regulations are both structured in the form of requirements to hold allowances. The first requirement applies at the source level: Specifically, at the compliance deadline after each control period, the owners and operators of each source covered by the program must surrender a quantity of allowances that is determined based on the emissions from the units at the source during the control period. The second requirement applies at the designated representative level (which typically is the owner or operator level): If the state's sources collectively emit in excess of the state's assurance level, the owners and operators of each set of sources determined to have contributed to the exceedance must surrender an additional quantity of allowances. As long as a source's owners and operators comply with these two allowance surrender requirements (and meet certain other requirements not related to the amounts of the sources' emissions), they are in compliance with the program.

In light of the operation of the Missouri sources, the EPA is doubtful that strengthening the assurance provisions by increasing allowance surrender requirements at the unit, source, or designated representative level would create a sufficient deterrent. Accordingly, the EPA is proposing instead to add a new, unit-level emissions limitation structured as a prohibition to emit NO_X in excess of a defined amount. A violation of the prohibition would not trigger additional allowance surrender requirements beyond the surrender requirements that would otherwise apply, but would trigger the possible application of the CAA's enforcement authorities. Because the purpose of the new unit-level emissions limitation would be to deter conduct causing exceedances of a state's assurance level, the EPA proposes to condition applicability of the new limitation on (1) the occurrence of an exceedance of the state's assurance level for the control period, and (2) the apportionment of at least some of the responsibility for the assurance level exceedance to the set of units represented by the unit's designated representative. Apportionment of responsibility for the assurance level exceedance would be carried out according to the existing assurance provision procedures and would therefore depend on the designated representative's shares of both the state's total emissions for the control period and the state's assurance level for the control period. The new emissions limitation would be in addition to, not in lieu of, the other requirements of the Group 3 trading program. This point would be made explicit by relabeling the source-level allowance holding requirement, currently called the "emissions limitation," as the "primary emissions limitation" and labeling the new unit-level requirement as the "secondary emissions limitation." (The regulations label the designated representative-level requirement as "compliance with the . . . assurance provisions.")

The EPA proposes to define the unit-level secondary emissions limitation by formula to reflect the amount of additional NO_X emissions caused by the unit's deviation from a benchmark seasonal average NO_X emissions rate during the control period, where the benchmark seasonal average NO_X emissions rate for the unit would be based on emissions rates the unit has achieved in the past plus a 25 percent margin. The EPA also proposes to use a floor for past performance of 0.08 lb/mmBtu (yielding 0.10 lb/mmBtu when the 25 percent margin is added), exclude control periods where the unit operated in less than 10 percent of the hours (in order to avoid data that might be unrepresentative), and screen out instances where the amount of additional emissions caused by the poor performance is less than 50 tons. Specifically:

- The EPA proposes to define a unit's secondary emissions limitation for a control period, in tons of NO_X, as the sum of 50 tons plus the product of (1) the unit's benchmark seasonal average emissions rate times (2) the unit's actual heat input for the control period, except that if the unit operated during less than 10 percent of the hours in the control period, no secondary emissions limitation would be defined for the unit for that control period.
- The EPA proposes to calculate the benchmark seasonal average NO_X

NO_X during the 2021 ozone season are available at *ampd.epa.gov.*

275 The EPA believes that the occurrence of avoidable assurance level exceedances under the Group 2 trading program, combined with the express statutory directive that good neighbor obligations must be addressed "within the state," and through "prohibition," would also provide a sufficient legal basis for the Agency to promulgate the same revisions to the assurance provisions for all the other CSAPR trading programs. The EPA is not proposing to do so at this time because the Agency has seen no reason to expect exceedances of the assurance levels under any of the other CSAPR trading programs by any of the states that will remain subject to the respective trading programs after this rulemaking, except possibly by Missouri under the CSAPR NO_X Annual Trading Program. The EPA expects that reductions in Missouri's seasonal NO_X emissions sufficient to comply with the proposed provisions of the revised Group 3 trading program, including the secondary emissions limitations, would also prevent exceedances of Missouri's currently applicable assurance level for annual NO_X emissions.

emissions rate for a unit for this purpose, in lb NO_X/mmBtu, as the higher of (1) 0.10 lb/mmBtu or (2) 125 percent of the unit's lowest seasonal average NO_X emissions rate in a previous control period under the CSAPR NO_X Ozone Season Group 1, Group 2, or Group 3 Trading Program, excluding any control periods where the unit operated for less than 10 percent of the hours in the ozone season.[276]

Table VII.B.8–1 shows the secondary emissions limitations that the proposed formula would have produced and which units would have exceeded those limitations if the limitations and formula had been in effect for the Group 2 trading program in 2019, 2020, and 2021 when assurance level exceedances occurred in Mississippi and Missouri. The EPA believes that in each case the formula functions in a reasonable manner, and the units identified as exceeding their respective secondary emissions limitations are sources for which an enforcement deterrent under CAA sections 113 and 304 would have been appropriate to compel better control of NO_X emissions.

TABLE VII.B.8–1—ILLUSTRATIVE RESULTS OF APPLYING PROPOSED SECONDARY EMISSIONS LIMITATION IN PREVIOUS INSTANCES OF ASSURANCE LEVEL EXCEEDANCES

Owner/operator	Unit	Benchmark NO_X emissions rate (lb/mmBtu)	Actual NO_X emissions rate (lb/mmBtu)	Secondary emissions limitation (tons)	Actual NO_X emissions (tons)	Exceedance (tons)
Mississippi—2019						
Miss. Power	Watson 4	0.137	0.176	458	524	66
Miss. Power	Watson 5	0.215	0.349	1,247	1,943	696
Mississippi—2020						
Entergy Miss.	Andrus 1	0.224	0.289	1,219	1,508	289
Miss. Power	Watson 5	0.215	0.286	1,086	1,381	295
Missouri—2020						
Assoc. Elec. Coop.	New Madrid 1	0.135	0.670	961	4,524	3,563
Assoc. Elec. Coop.	New Madrid 2	0.131	0.497	866	3,108	2,242
Assoc. Elec. Coop.	Thomas Hill 1	0.123	0.526	374	1,384	1,010
Assoc. Elec. Coop.	Thomas Hill 2	0.122	0.537	548	2,187	1,639
Assoc. Elec. Coop.	Thomas Hill 3	0.104	0.195	780	1,374	594
Missouri—2021						
Assoc. Elec. Coop.	New Madrid 1	0.135	0.652	353	1,466	1,113
Assoc. Elec. Coop.	New Madrid 2	0.131	0.611	1,054	4,700	3,646
Assoc. Elec. Coop.	Thomas Hill 1	0.123	0.146	421	440	19
Assoc. Elec. Coop.	Thomas Hill 2	0.122	0.400	600	1,801	1,201

For further illustrations of the application of the proposed formula and secondary emissions limitation to other units in the states proposed to be subject to the expanded Group 3 trading program in the control periods from 2016 through 2021, see the spreadsheet ''Illustrative Calculations Using Proposed Secondary Emissions Limitation Formula'', available in the docket. The EPA notes that, with the exception of the units listed in Table VII.B.8–1, no unit shown in the spreadsheet as having emissions exceeding the illustrative secondary emissions limitation calculated for the unit would have violated the proposed prohibition because no violation would occur in the absence of an exceedance of the assurance level and apportionment of responsibility for a share of the exceedance to the unit under the assurance provisions.

The EPA requests comment on the proposal to establish a secondary emissions limitation for the Group 3 trading program as described in this section. The EPA specifically requests comment on the proposed form of the secondary emissions limitation, the proposed formula for computing each unit's secondary emissions limitation, and the proposed values for the screening parameters used in the calculations.

9. Unit-Level Allowance Allocation and Recordation Procedures

In the Revised CSAPR Update, the EPA established default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances (''Group 3 allowances'') in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. The EPA also provided states with several options to submit SIP revisions which, if approved, would result in the replacement of EPA's allowance allocations with state-determined allowance allocations for the 2022 control period and beyond. The current regulations (*i.e.,* before this proposed rule) provide that EPA's allocations and allocation procedures apply for the 2021 control period and, by default, for subsequent control periods unless and until a state provides state-determined allowance allocations under an approved SIP revision.

The current default allocation process for the Group 3 trading program established in the Revised CSAPR Update involves three main steps. First, a portion of each state emissions budget for each control period is reserved for potential allocation to units that are subject to allowance holding requirements and that would not otherwise receive allowance allocations in the overall allocation process. Under the current Group 3 trading programs, the reserved allowances are made available generally (but not exclusively[277]) to ''new'' units—which for purposes of the Revised CSAPR Update means units commencing commercial operation on or after January 1, 2019—through a ''new unit set-aside'' established for qualifying units in each state and, if areas of Indian country exist within the state's borders, a separate ''Indian country new unit set-

[276] In proposing a formulation for a benchmark rate for the specific regulatory purpose of defining a secondary emissions limitation under the Group 3 trading program, the EPA is not expressing a view that the same formulation of a benchmark rate would be suitable for any other regulatory purpose.

[277] The units qualifying for allocations from a new unit set-aside may include not only units that have recently started operating but also units that previously received, but are no longer eligible to receive, allocations from the unreserved portion of the budget as ''existing'' units.

aside'' for qualifying units in such Indian country. Second, in advance of each control period, the unreserved portion of the state budget is allocated among the state's eligible ''existing'' units—which for purposes of the Revised CSAPR Update generally means units that commenced commercial operation before January 1, 2019—and the allocations are recorded in the respective sources' compliance accounts. Finally, after the control period but before the compliance deadline by which sources must hold allowances to cover their emissions for the control period, allowances from the reserved portions of the budget are allocated to qualifying units, any remaining reserved allowances not allocated to qualifying units are allocated among the state's existing units, and the allocations are recorded in the respective sources' compliance accounts.

In this rulemaking, the EPA would retain the overall three-step allocation process summarized above but is proposing revisions to each step to better address units in Indian country and to better coordinate the unit-level allocation process with the proposed dynamic budget-setting process discussed in Section VII.B.4 of this proposed rule. Like the allocation process established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, the revised process proposed in this rulemaking would be designed to provide default allowance allocations to all units that are subject to allowance holding requirements, including, for the first time under any CSAPR trading program, an existing EGU in Indian country not covered by a state's CAA implementation planning authority. The proposed revisions to the three steps are discussed in Sections VII.B.4.a, VII.B.4.b, and VII.B.4.c of this proposed rule, respectively.

Echoing the approach to unit-level allocations followed in CSAPR, the CSAPR Update, and the Revised CSAPR Update, in this rulemaking, EPA is again proposing to provide states with several options to submit SIP revisions which, if approved, would result in the replacement of EPA's default allocations with state-determined allocations for subsequent control periods. Specifically, the proposed regulations would provide that EPA's allocations and allocation procedures will apply for the 2023 control period and, by default, for subsequent control periods unless and until a state provides state-determined allocations under an approved SIP revision. The options to submit SIP revisions that would accomplish this purpose are discussed in Section VII.D of this document. Similarly, for a covered area of Indian country not subject to a state's CAA implementation planning authority, a tribe could elect to work with the EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations that would replace EPA's default allocations for subsequent control periods.

a. Set-Asides of Portions of State Emissions Budgets for New Units

As the first step in the default allocation process that the EPA has applied under CSAPR, the CSAPR Update, and the Revised CSAPR Update for any control period where a state does not employ an alternative allocation process pursuant to an approved SIP revision, EPA has reserved a portion of the state's emissions budget for potential allocation to units that are subject to allowance holding requirements and that would not otherwise receive allowance allocations in the overall allocation process. Consistent with the budget-setting approach in those rulemakings, where the state emissions budgets for all future control periods were determined in the initial rulemakings, the amounts of the reserved portions of the budgets were also determined in the initial rulemakings.[278]

The units for which portions of the budgets were reserved in set-asides have fallen into two main categories: First, units for which the data needed to determine allowance allocations does not exist at the time when the allocations for other units were being determined—*i.e.,* ''new'' units[279]—and second, units that would be left out if a state chooses to replace EPA's default allocations with state-determined allocations—*i.e.,* any units in Indian country not covered by a state's CAA implementation planning authority. Because there were no existing units in what the EPA understood to be Indian country for purposes of CSAPR, the CSAPR Update, and the Revised CSAPR Update, potential units in Indian country were considered to be a subcategory of ''new'' units, and the two types of set-asides that have been created are ''new unit set-asides'' and ''Indian country new unit set-asides.'' The principal difference between these two types of set-asides under the regulations for all of the CSAPR trading programs has been that a state can take over administration of the allowances allocated to a new unit set-aside from the EPA through an approved SIP revision but cannot take over administration of the allowances allocated to an Indian country new unit set-aside.

In this rulemaking, the EPA is proposing several revisions affecting the establishment of set-asides. The first proposed revision, which is largely unrelated to the other aspects of this rulemaking, would update the regulations for the Group 3 trading program[280] to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that the relevant states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area.[281] Consistent with this holding, EPA is proposing to revise language in the Group 3 trading program regulations that, for purposes of allocating allowances from a given state's emissions budget, currently distinguishes between (1) the set of units within the state's borders that are not in Indian country and (2) the set of units within the state's borders that are in Indian country. As revised, the provisions would distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. The revised language would more accurately distinguish which units are, or are not, covered by a state's CAA implementation planning authority, which is the underlying purpose for which the term ''Indian country'' is currently used in the allowance allocation provisions. The effect of the proposed revision would be that any

[278] Under the current regulations for each of the CSAPR trading programs, when a unit that has received allocations as an ''existing'' unit ceases operation, after a specified number of control periods the unit loses the allocations, which are then allocated to the state's new unit set-asides for subsequent control periods.

[279] A unit that has received allocations as an ''existing'' unit, then loses its allocations because of non-operation, and then later resumes operation is treated as a type of ''new'' unit for allocations purposes.

[280] As further discussed in Section VII.B.12 of this proposed rule, the EPA is also proposing to make this revision to the regulations for the other CSAPR trading programs in addition to the Group 3 trading program.

[281] For additional discussion of the *ODEQ* v. *EPA* decision and other issues related to the CAA implementation planning authority of states, tribes, and the EPA in various areas of Indian country, *see* Section IV.C.2 of this proposed rule.

units located in areas of ''Indian country'' as defined in 18 U.S.C. 1151 that are covered by a state's CAA implementation planning authority would be treated for allowance allocation purposes in the same manner as units in areas of the state that are not Indian country, consistent with the *ODEQ* holding.[282]

The remaining proposed revisions, which are interrelated, concern the types of set-asides that in the context of this proposal will best accomplish the goal of ensuring the availability of allocations to units that are subject to allowance holding requirements and that would not otherwise receive allowance allocations. One proposed revision to the types of set-asides addresses allocations to existing units in Indian country. The revised geographic scope of the Group 3 trading program under this proposal would for the first time include an existing EGU in Indian country not covered by a state's CAA implementation planning authority—the Bonanza coal-fired unit in the Uintah and Ouray Reservation within Utah's borders. In order to provide an option for Utah (or a similarly situated state in the future) to replace EPA's default allowance allocations to most existing units with state-determined allocations through a SIP revision while continuing to ensure the availability of a default allocation to the Bonanza unit (or similarly situated units in the future), the EPA proposes to revise the Group 3 trading program regulations to provide for ''Indian country existing unit set-asides.'' Specifically, for each state and for each control period where the inventory of units used to compute the state's emissions budget includes one or more existing units[283] in an area of Indian country not covered by the state's CAA implementation planning authority, the EPA would reserve a portion of the state's emissions budget in an Indian country existing unit set-aside for the unit or units. The amount of each Indian country existing unit set-aside would equal the sum of the default allocations that the units covered by the set-aside would receive if the allocations to all existing units within the state's borders were computed according to EPA's default allocation procedure (which is discussed in Section VII.B.9.b of this proposed rule). Immediately after determining the amount of a state's emissions budget for a control period (and after reserving a portion for potential allocation to new units, as discussed below), the EPA would first determine the default allocations for all existing units within the state's borders, then allocate the appropriate quantity of allowances to the Indian country existing unit set-aside, then allocate the allowances from the set-aside to the covered units in Indian country, and finally record the allocations in the sources' compliance accounts at the same time as the allocations to other sources not in Indian country. The existence of the Indian country existing unit set-aside thus would have no substantive effect unless and until the relevant state chose to replace EPA's default allowance allocations through a SIP revision, in which case the state would have the ability to establish state-determined allocations for the units subject to the state's CAA implementation planning authority while the EPA would continue to administer the Indian country existing unit set-aside for the units in Indian country not covered by the state's CAA implementation planning authority.[284] The EPA believes the proposal to establish Indian country existing unit set-asides would accomplish the objective of allowing states to control allowance allocations to units covered by their CAA implementation planning authority while providing equitable allocations to units in Indian country not covered by such authority.

The remaining revisions to the types of set-asides address the set-asides used to ensure availability of allowance allocations to *new* units in light of the division of the budget for *existing* units into a reserved portion for existing units in Indian country and an unreserved portion for other existing units. Under the current Group 3 trading program regulations, allowances for new units are provided from separate new unit set-asides and Indian country new unit set-asides. The EPA proposes to combine these two types of set-asides starting with the 2023 control period by eliminating the Indian country new unit set-asides and expanding eligibility for allocations from the new unit set-asides to include units anywhere within the relevant states' borders. However, as with the Indian country new unit set-asides under the current regulations, the EPA would continue to administer the new unit set-asides in the event a state chose to replace EPA's default allocations to existing units with state-determined allocations, thereby ensuring the availability of allocations to any new units not covered by a state's CAA implementation planning authority.

The reason for the proposed revisions to the new unit set-asides and Indian country new unit set-asides is to avoid unnecessary and potentially inequitable changes to the degree to which individual existing units contribute to, or benefit from, the new unit set-asides. Under the current regulations, the allowances used to establish these set-asides are reserved from each state emissions budget before determination of the allocations from the unreserved portion of the budget to existing units, so that certain existing units—generally those receiving the largest allocations—contribute to creation of the set-asides through roughly proportional reductions in their allocations. Later, if any allowances in a set-aside are not allocated to qualifying new units, the remaining allowances are reallocated to the existing units in proportion to their initial allocations from the unreserved portion of the budget, so that certain existing units—again, generally those receiving the largest allocations—benefit from the reallocations in rough proportion to their previous contributions.[285] The EPA believes maintaining this symmetry, where the same existing units—whether in Indian country or not—both contribute to and potentially benefit from the set-asides, is a reasonable policy objective, and doing so requires that the EPA continue to administer the new unit set-asides in the event a state chooses to replace EPA's default allocations to existing units with state-determined allocations, because otherwise the EPA would be unable to ensure that the units in Indian country would receive an appropriate

[282] The EPA notes that the units that would be treated for allocation purposes in the same manner as units not in Indian country would include units in any areas of Indian country subject to a state's CAA implementation planning authority, whether those are non-reservation areas (consistent with *ODEQ*) or reservation areas (such as areas of Indian country within Oklahoma's borders covered by the EPA's October 1, 2020 approval of Oklahoma's request under SAFETEA, as discussed in Section IV.C.2 of this proposed rule).

[283] In coordination with the dynamic budgeting process discussed in Section VII.B.4 of this proposed rule, each unit included in the unit inventory used to determine a state's emissions budget for a given control period in 2025 or a later year would be considered an ''existing'' unit for that control period for purposes of the determination of unit-level allowance allocations. In other words, there would no longer be a single fixed date that would divide ''existing'' from ''new'' units.

[284] As noted in Section VII.D, of this proposed rule a tribe could elect to work with EPA under the Tribal Authority Rule to develop a full or partial tribal implementation plan under which the tribe would determine allowance allocations for units in the relevant area of Indian country that would replace EPA's default allocations for subsequent control periods.

[285] Allowances from an Indian country new unit set-aside that are not allocated to qualifying new units are first transferred to the state's new unit set-aside, and if the allowances are still not allocated to qualifying new units, the allowances are then reallocated to the state's existing units.

share of any reallocated allowances.[286] Since the principal difference between the new unit set-asides and the Indian country new unit set-asides under the current regulations is that the EPA continues to administer the Indian country new unit set-asides in the event a state chooses to replace EPA's default allocations with state-determined allocations, if under the revised regulations the EPA would need to continue to administer the new unit set-asides, then there would no longer be any reason to establish separate Indian country new unit set-asides.

With respect to the total amounts of allowances that would be set aside for potential allocation to new units from the emissions budgets for each state, for the control periods in 2023 and 2024 (but not for subsequent control periods, as discussed below), EPA proposes to establish total set-aside amounts equal to the projected amounts of emissions from any planned units in the state for the control period, plus an additional 2% of the state emissions budget to address any unknown new units. For example, if planned units in a state are projected to emit 3% of the state's NO_X ozone season emissions budget, then the new unit set-aside for the state would be set at 5 percent, which is the sum of the minimum 2% set-aside plus an additional 3 percent for planned units. This is the same approach previously used to establish the amounts of new unit set-asides in CSAPR, the CSAPR Update, and the Revised CSAPR Update for all the CSAPR trading programs. *See, e.g.,* 76 FR 48292 (August 8, 2011). As under the Revised CSAPR Update, EPA proposes to make an exception for New York for the 2023 and 2024 control periods, establishing a total new unit set-aside amount for each control period of 5 percent of the state's emissions budget, with no additional consideration for planned units, because this approach is consistent with New York's preferences as reflected in an approved SIP addressing allowance allocations for the Group 2 trading program. Because the amounts of the state emissions budgets for the 2023 and 2024 control periods would be determined in the rulemaking, the amounts of the new unit set-asides for these control periods would also be determined in the rulemaking. The proposed amounts are shown in Tables VII.B.9.a-1 and VII.B.9.a-2 of this proposed rule.

TABLE VII.B.9.a–1—PROPOSED CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2023 CONTROL PERIOD [a]

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,364	3	191
Arkansas	8,889	2	178
Delaware	384	14	54
Illinois	7,364	5	368
Indiana	11,151	2	223
Kentucky	11,640	2	233
Louisiana	9,312	2	186
Maryland	1,187	2	24
Michigan	10,718	4	429
Minnesota	3,921	2	78
Mississippi	5,024	2	100
Missouri	11,857	2	237
Nevada	2,280	6	137
New Jersey	799	2	16
New York	3,763	5	188
Ohio	8,369	5	418
Oklahoma	10,265	2	205
Pennsylvania	8,855	3	266
Tennessee	4,234	2	85
Texas	38,284	2	766
Utah	14,981	3	449
Virginia	3,090	5	155
West Virginia	12,478	2	250
Wisconsin	5,963	2	119
Wyoming	9,125	3	274

Table Notes:

[a] In the event a final rule in this rulemaking becomes effective after May 1, 2023, the emissions budgets for the 2023 control period would be adjusted under the rule's proposed transitional provisions to ensure the new budgets would apply only after the rule's effective date, even though the revised Group 3 trading program would be implemented for most sources as of the start of the 2023 ozone season on May 1, 2023. The 2023 budget amounts shown in Table VII.B.9.a–1 do not reflect these possible adjustments. The transitional provisions are discussed in Section VII.B.11 of this proposed rule.

[286] If units in Indian country were unable to share in the benefits of reallocation of allowances from the new unit set-asides, it would be possible to achieve a different form of symmetry by simultaneously exempting the units in Indian country from the obligation to share in the contribution of allowances to the new unit set-asides. However, some stakeholders might view this alternative as potentially inequitable because existing units in Indian country would then make no contributions toward the new unit set-aside while other existing units would still be required to do so.

TABLE VII.B.9.a–2—PROPOSED CSAPR NO_X OZONE SEASON GROUP 3 NEW UNIT SET-ASIDE (NUSA) AMOUNTS FOR THE 2024 CONTROL PERIOD

State	Emissions budgets (tons)	New unit set-aside amount (percent)	New unit set-aside amount (tons)
Alabama	6,306	3	189
Arkansas	8,889	2	178
Delaware	434	14	61
Illinois	7,463	5	373
Indiana	9,391	2	188
Kentucky	11,640	2	233
Louisiana	9,312	2	186
Maryland	1,187	2	24
Michigan	10,718	4	429
Minnesota	3,921	2	78
Mississippi	4,400	2	88
Missouri	11,857	2	237
Nevada	2,372	6	142
New Jersey	799	2	16
New York	3,763	5	188
Ohio	8,369	5	418
Oklahoma	9,573	2	191
Pennsylvania	8,855	3	266
Tennessee	4,234	2	85
Texas	38,284	2	766
Utah	15,146	3	454
Virginia	2,814	5	141
West Virginia	12,478	2	250
Wisconsin	5,057	2	101
Wyoming	8,573	3	257

For control periods in 2025 and later years, the EPA proposes to allocate a total of 2% of each state emissions budget to a new unit set-aside, with no additional amount for planned new units. The amounts of the set-asides for each state and control period would be computed when the emissions budgets for the control period are established, by May 1 of the year before the year of the control period. The procedure for determining the amounts of the set-asides based on the amounts of the state emissions budgets would be codified in the Group 3 trading program regulations and would reflect the same percentage of the emissions budget for all states.

The purpose of the proposed change to the procedure for establishing the amounts of the set-asides is to coordinate with the dynamic budget-setting process that would also become effective as of the 2025 control period. As discussed in Section VII.B.4 of this proposed rule, under the dynamic budget-setting process, each state's budget for each control period would be computed using fleet composition information and the total ozone season heat input reported by all affected units in the state for the latest control period before the budget-setting computations, which would be 2 years before the control period for which the budgets are being determined. (For example, 2025 emissions budgets would be based on 2023 fleet composition and heat input data.) Moreover, as discussed in Section VII.B.9.b of this proposed rule, all units whose heat input was used in the budget computations for a given control period would be eligible to receive allocations as ''existing'' units in that control period. Consequently, by the 2025 control period, all or almost all units that commence commercial operation before issuance of a final rule in this rulemaking would be considered ''existing'' units for purposes of budget-setting and allocations, and units commencing commercial operation after issuance of a final rule generally would be considered ''existing'' units for all but their first two full control periods of operation (and possibly a preceding partial control period). Given that new units would not be relying on the new unit set-asides as a permanent source of allowances, as is the case for ''new'' units under the other CSAPR trading programs, the EPA believes smaller set-asides would be sufficient.

The EPA requests comment on the proposals to establish Indian country existing unit set-asides, eliminate Indian country new unit set-asides, and expand eligibility for allocations from new unit set-asides to include units in Indian country for control periods in 2023 and later years. In the alternative, the EPA requests comment on establishing emissions budgets (and assurance levels and new unit set-asides) for the Uintah and Ouray Reservation separate from the emissions budgets (and assurance levels, new unit set-asides, and Indian country new unit set-asides) established for the remaining lands within Utah's borders, and otherwise retaining the structure of prior CSAPR trading programs' approach to allocations to new units in Indian country (*i.e.,* keeping the Indian country new unit set-asides, and not expanding eligibility for allocations from the new unit set-asides). The EPA also requests comment on the proposed new unit set-aside amounts for the 2023 and 2024 control periods, the proposed procedure for establishing the new unit set-aside amounts for the control periods in 2025 and later years, and the proposed procedure for establishing the Indian country existing unit set-aside amounts for the control periods in 2023 and later years.

b. Allocations to Existing Units, Including Units That Cease Operation

In conjunction with the new and revised state emissions budgets for the Group 3 trading program proposed in this rulemaking, the EPA is necessarily proposing new unit-level allocations of Group 3 allowances to existing units.[287]

[287] The proposed revisions to the procedures for computing unit-level allowance allocations in this rulemaking apply only to the Group 3 trading

The procedure that the EPA proposes to employ to compute the unit-level allocations is very similar but not identical to the procedure used to compute unit-level allocations for units subject to the Group 3 trading program in the Revised CSAPR Update. The steps of the proposed procedure for determining allocations from each state emissions budget for each control period, are described in detail in the Unit-Level Allowance Allocations Proposed Rule TSD. The steps are summarized later, with changes from the procedure followed in the Revised CSAPR Update noted.

In the first step, the EPA would identify the list of units eligible to receive allocations for the control period, which would be the same set of units whose heat input was used in computing the state's emissions budget for the control period (except any units that are included in the budgets as ''new'' units, which would receive allocations from the new unit set-asides instead). The unit inventories used to compute emissions budgets for the 2023 and 2024 control periods would be determined in the rulemaking in the same manner as in the Revised CSAPR Update. The unit inventories used to compute emissions budgets and unit-level allocations for control periods in 2025 and later years would be determined in the year before the control period in question based on the latest reported emissions and operational data, which is an extension of the methodology used in the Revised CSAPR Update to reflect more recent data (for example, the unit inventories used to compute 2025 budgets and allocations would reflect reported data for the 2023 control period). The procedures for updating the unit inventories for 2023 and 2024 and for 2025 and beyond are discussed in Section VII.B.4 of this proposed rule, and the criteria that the EPA has applied to determine whether a unit's scheduled retirement is sufficiently certain to serve as a basis for adjusting emissions budgets and unit-level allocations are discussed in Section VI.B and in the Ozone Transport Policy Analysis Proposed Rule TSD. With regard to the use of the inventories from the budget-setting procedure in setting unit-level allocations, in the Revised CSAPR Update, the inventories used to establish the budgets were generally also used to compute unit-level allocations, except that units that commenced construction after January 1, 2019, were not treated as eligible to receive allocations as existing units and instead received allocations from the new unit set-asides. Under this rulemaking, any unit whose heat input is used to set a state's emissions budget for a given control period would also be eligible to receive allocations as an existing unit for that control period.

The EPA notes that this proposal to base the list of eligible units on the list of units that reported heat input in the control period 2 years earlier than the control period for which allocations are being determined would represent a revision to the current regulations concerning the treatment of allocations to retired units. Under the current regulations, units that cease operations for 2 consecutive control periods continue to receive allocations as existing units for 3 additional years (that is, a total of 5 years) before the allowances they would otherwise have received are reallocated to the new unit set-aside for the state. Under the proposal in this rulemaking, units that cease operation would receive allocations for only two full control periods of non-operation. While the EPA has in prior transport rulemakings noted a qualitative concern that ceasing allowance allocations prematurely could distort the economic incentives of EGUs to continue operating when retirement is more economical, the EPA believes current market conditions are such that a continuation of allowance allocations to retiring units likely has no more than a de minimis effect on the consideration of an EGU whether to retire or not.

In the second step of the procedure for determining allocations to existing units, the EPA would compile a database containing for each eligible unit the unit's historical heat input and total NO_X emissions data for the five most recent ozone seasons. For each unit, the EPA would compute an average heat input value based on the three highest non-zero heat input values over the 5-year period, or as the average of all the non-zero values in the period if there are fewer than three non-zero values. For each unit, the EPA would also determine the maximum total NO_X emissions value over the 5-year period. These procedures are nearly identical to the procedures used in the Revised CSAPR Update, with two exceptions. First, instead of using only the data available at the time of the rulemaking, for each control period the EPA would use data from the most recent five control periods for which data had been reported. (For example, for the 2025 control period, the EPA would use data for the 2019–2023 control periods.) Second, to simplify the data compilation process, the EPA would use only a five-year period for NO_X mass emissions, in contrast to the 8-year period used in the Revised CSAPR Update for NO_X mass emissions.

In the third step of the procedure for determining allocations to existing units in each state, the EPA would allocate the available allowances for that state among the state's eligible units in proportion to the share each unit's average heat input value represents of the total of the average heat input values for all the state's eligible units, but not more than the unit's maximum total NO_X value. If the allocations to one or more units are curtailed because of the units' maximum total NO_X values, the EPA would iterate the calculation procedure as needed to allocate the remaining allowances, excluding from each successive iteration any units whose allocations have already reached their maximum total NO_X values. This calculation procedure is identical to the calculation procedure used in the Revised CSAPR Update (as well as the CSAPR Update and CSAPR).

The unit-level allocations for the 2023 and the 2024 control periods would be determined in the rulemaking based on the emissions budgets for those control periods also determined in the rulemaking and would be recorded 30 days after the effective date of the final rule (in order to provide time to execute the proposed recall of 2023 and 2024 Group 2 allowances, as discussed in Section VII.B.11.c of this proposed rule). This proposed recordation schedule represents a revision to the recordation schedule currently in the Group 3 trading program regulations which calls for allocations of 2023 and 2024 Group 3 allowances to existing units to be recorded on July 1, 2022. The EPA notes that for the three states with approved SIP revisions establishing their own methodologies for allocating Group 2 allowances—Alabama, Indiana, and New York—EPA proposes to follow those methodologies to the extent possible in developing the allocations of Group 3 allowances for the 2023 and 2024 control periods. For the amounts of the proposed allocations to existing units for the 2023 and 2024 control periods, see the ''Unit-Level Allowance Allocations Proposed Rule TSD'' in the docket.

The unit-level allocations for each control period in 2025 or a later year would be computed immediately following the determination of the emissions budgets for the control period. The EPA would perform the

program. In this rulemaking, the EPA is not proposing changes to or reopening the methodology for computing the amounts of allowances allocated to any unit under any other CSAPR trading program.

computations and issue a notice of data availability concerning the preliminary unit-level allocations for each control period by March 1 of the year before the control period. Objections to the data and preliminary computations could be submitted for 30 days, and the EPA would make any appropriate revisions and issue another notice of data availability by May 1 of the year before the control period. The EPA would then record the allocations by July 1 of the year before the control period. This proposed recordation schedule—which is necessitated by the fact that the amounts of the unit-level allocations to be recorded would not be known until the year before the control period, as just discussed—represents a revision to the recordation schedule currently in the Group 3 trading program regulations which calls for allocations of Group 3 allowances to existing units for control periods in 2025 and later years to be recorded on July 1 of the third year before the year of the control period. The EPA does not propose to follow any state-specific methodologies as part of the procedures for determining default unit-level allocations of Group 3 allowances for control periods in 2025 or later years, but any state wishing to use a procedure different than EPA's default allocations procedure could do so by obtaining approval of a SIP revision, as discussed in Section VII.D of this proposed rule.

In the case of any states making state-determined allocations under approved SIP revisions, the allocations would have to be submitted to EPA by June 1 of the year before the control period and the EPA would record the allocations by July 1 of the year before the control period. The proposed submission deadline would represent a revision of the current deadline of June 1 of the year 3 years before the control period, and the proposed recordation deadline would represent a revision of the current deadline of July 1 of the year 3 years before the control period. The purpose of revising the submission deadline is to provide each state for which the EPA has approved a SIP revision authorizing state-determined allowance allocations a period of time in which to apply the state's preferred allocation methodology to the state's trading budget for the appropriate control period. Because the state trading budgets under the Group 3 trading program as revised would not be known until May 1 of the year before each control period, states could not determine unit-level allocations of the budgets using their own methodologies significantly before June 1 of the year before the control period. Submission by June 1 would allow the allowance allocations to the units in the state to be recorded by July 1 of the year before the control period, simultaneously with the recordation of allocations to units in states where the EPA determines the allocations.

As an exception to all of the recordation deadlines that would otherwise apply, the EPA proposes to not record any allocations of Group 3 allowances in a source's compliance account unless that source has complied with the requirements to surrender previously allocated 2023–2024 Group 2 allowances. The surrender requirements are necessary to maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this final rule. The EPA finds that it is reasonable to condition the recordation of Group 3 allowances on compliance with the surrender requirements because the condition will spur compliance and will not impose an inappropriate burden on sources. The EPA considers establishment of this condition, which will facilitate the continued functioning of the Group 2 trading program, to be an appropriate exercise of the Agency's authority under CAA section 301 (42 U.S.C. 7601) to prescribe such regulations as are necessary to carry out its functions under the Act.

The EPA requests comment on the proposed revisions to the procedures for allocating allowances to existing units under the Group 3 trading program, the deadlines for recording the allocations, and the deadlines for submission of state-determined allowance allocations to the EPA.

c. Allocations From Portions of State Emissions Budgets Set Aside for New Units

As promulgated in the Revised CSAPR Update, the Group 3 trading program regulations provide for the EPA to allocate allowances from each new unit set-aside and Indian country new unit set-aside after the end of the control period at issue. The regulations call for the EPA to allocate allowances to any eligible ''new'' units in the state in proportion to their respective emissions during the control period, up to the amounts of those emissions if the relevant set-aside contains sufficient allowances, and not exceeding those emissions. An eligible new unit for purposes of allocations from a set-aside for a given control period is generally any unit in the relevant area that reported emissions subject to allowance surrender requirements during the control period and that was not eligible to receive an allowance allocation as an ''existing'' unit for the control period. Any allowances remaining in an Indian country new unit set-aside after the allocations to new units are transferred to the new unit set-aside for the state for potential allocation to new units in non-Indian country areas of the state, and any allowances remaining in a new unit set-aside after the allocations to new units are reallocated to the existing units in the state in proportion to those units' previous allocations for the control period as existing units. The EPA issues a notice of data availability concerning the proposed allocations by March 1 following the control period, provides an opportunity for submission of objections, and issues a final notice of data availability and record the allocations by May 1 following the control period, one month before the June 1 compliance deadline.

In this rulemaking, as discussed in Section VII.B.9.a of this document, the EPA is proposing to eliminate Indian country new unit set-asides after the 2022 control period and to expand eligibility for allocations from each state's new unit set-aside for a control period in 2023 or a later year to include units in Indian country within the state's borders, regardless of whether the area of Indian country is covered by the state's CAA implementation planning authority. The reasons for these proposed revisions are discussed in Section VII.B.9.a of this proposed rule. The EPA is not proposing any substantive revisions to the current Group 3 trading program provisions governing the procedures for allocating allowances from a state's new unit set-aside for a control period to the eligible units within the state's borders.[288]

This EPA notes that the proposed revisions to other provisions of the Group 3 trading program regulations discussed elsewhere in this document will reduce the portions of the state emissions budgets that are allocated through the new unit set-asides. Specifically, because the new unit set-asides will no longer receive any additional allowances when units retire, for control periods in 2025 and later years the amounts of allowances in the new unit set-asides will always be 2 percent of the respective state emissions budgets for the respective control periods. This reduction in the size of the

[288] As discussed in Section X of this proposed rule, the EPA is proposing to relocate some of the regulatory provisions relating to administration of the new unit set-asides and is also proposing to remove certain provisions that would be made obsolete by proposed revisions to other provisions of the Group 3 trading program regulations.

new unit set-asides is appropriate given that the number of consecutive control periods for which any particular unit is likely to receive allocations from a state's new unit set-aside will be reduced to two or three before the unit becomes eligible to receive allocations from the unreserved portion of the state's emissions budget. This approach contrasts with the approach under the other CSAPR trading programs where a new unit never becomes eligible to receive allocations from the unreserved portion of the emissions budget and where the new unit set-aside therefore needs to grow to accommodate an ever-increasing share of the state's total emissions.

The EPA also notes that, as discussed in Sections VII.D.2 and VII.D.3 of this proposed rule, in the event that a state chooses to replace EPA's default allowance allocations under the Group 3 trading program with state-determined allocations through a SIP revision, the EPA will continue to administer the portion of each state emissions budget reserved in a new unit set-aside in order to ensure the availability of allowance allocations to new units in any areas of Indian country within the state not covered by the state's CAA implementation planning authority.

d. Incorrectly Allocated Allowances

The Group 3 trading program regulations as promulgated in the Revised CSAPR Update include provisions addressing incorrectly allocated allowances. With regard to any allowances that were incorrectly allocated and are subsequently recovered, the current provisions generally call for the recovered allowances to be reallocated to other units in the relevant state (or Indian country within the borders of the state) through the process for allocating allowances from the new unit set-aside (or Indian country new unit set-aside) for the state. If the procedures for allocating allowances from the set-asides have already been carried out for the control period for which the recovered allowances were issued, the allowances would be allocated through the set-asides for subsequent control periods.

The EPA continues to view the current provisions for disposition of recovered allowances as reasonable in the case of any allowances that are recovered before the deadline for recording allocations of allowances from the new unit set-aside for the control period for which the recovered allowances were issued. However, in the case of any allowances that are recovered after that deadline, adding the recovered allowances to the new unit set-aside for a subsequent control period, as provided in the current regulations, would be inconsistent with the proposed trading program enhancements discussed elsewhere in this document, where the amounts of allowances provided in the state emissions budgets for each control period are designed to reflect the most current available information on fleet composition and utilization and where the quantities of banked allowances available for use in each control period are recalibrated for consistency with the state emissions budgets. The EPA therefore proposes that, starting with allowances allocated for the 2024 control period, any incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-aside for that control period (*i.e.,* May 1 of the year following the control period) would be transferred to a surrender account instead of being reallocated to other units in the state.

The EPA requests comment on the proposed revision to the provisions for disposition of incorrectly allocated allowances that are recovered after the deadline for allocating allowances from the new unit set-asides for the control periods for which the recovered allowances were issued.

10. Other Trading Program Provisions

This section discusses how certain existing provisions of the Group 3 trading program regulations would apply to sources that become subject to the program as a result of a final rule in this rulemaking as well as certain proposed changes to reporting requirements associated with the proposed backstop daily NO_X emissions rates for coal-fired units.

a. Designated Representative Requirements

As noted in Section VII.B.1.a of this document, a core design element of all the CSAPR trading programs is the requirement that each source must have a designated representative who is authorized to represent all of the source's owners and operators and is responsible for certifying the accuracy of the source's reports to the EPA and overseeing the source's Allowance Management System account. The necessary authorization of a designated representative is certified to the EPA in a certificate of representation. The EPA is not proposing any change to the Group 3 trading program's designated representative provisions in this rulemaking.

The existing designated representative provisions in the Group 3 trading program regulations already provide that EPA will interpret references to the Group 2 trading program in certain documents—including a certificate of representation as well as a notice of delegation to an agent or an application for a general account—as if the documents referenced the Group 3 trading program instead of the Group 2 trading program. For these reasons, sources that currently participate in the Group 2 trading program and that transition to the Group 3 trading program because of a final rule in this rulemaking will not need to submit any new forms as part of the transition, because previously submitted forms will be valid for purposes of the Group 3 trading program.

Designated representatives for sources that are newly affected under the Group 3 trading program and that are not currently affected under the Group 2 trading program would need to submit new or updated certificates of representation. If the source is also affected under other CSAPR trading programs or the Acid Rain Program, the source's designated representative for all of the programs must be the same individual. The EPA will not record any Group 3 allowances allocated to a source in the source's compliance account until the source has a properly authorized designated representative.

b. Monitoring and Reporting Requirements

The Group 3 trading program requires monitoring and reporting of emissions and heat input data in accordance with the provisions of 40 CFR part 75. In this rulemaking, the EPA is not proposing any change to these provisions of the Group 3 trading program except with respect to the monitor certification deadline for certain units. The EPA is also not proposing any changes to the monitoring requirements in 40 CFR part 75 for units subject to such requirements. However, because of the proposed geographic expansion of the Group 3 trading program, certain units that were not previously subject to monitoring requirements under 40 CFR part 75 would become subject to such requirements. Also, the EPA is proposing certain additional recordkeeping and reporting requirements that would be met using some of the data that are already collected by the required monitoring systems.[289]

[289] The EPA is not proposing to amend the existing provisions of the Group 3 trading program regulations that govern whether units covered by the program must record and report required data on a year-round basis or may elect to record and

Continued

Under 40 CFR part 75, a unit has several options for monitoring and reporting, including the use of continuous emissions monitoring systems (CEMS), excepted monitoring methodologies for qualifying gas- or oil-fired units that rely in part on fuel-flow metering in combination with CEMS-based or testing-based NO_X emissions rate data, low-mass emissions monitoring for certain non-coal-fired, low emitting units, and alternative monitoring systems approved by the Administrator through a petition process. In addition, sources can submit petitions to the Administrator for alternatives to individual monitoring, recordkeeping, and reporting requirements specified in 40 CFR part 75. Each CEMS must undergo rigorous initial certification testing and periodic quality assurance testing thereafter, including the use of relative accuracy test audits and 24-hour calibrations. In addition, when a monitoring system is not operating properly, standard substitute data procedures are applied to produce a conservative estimate of emissions for the period involved. Further, 40 CFR part 75 requires electronic submission of quarterly emissions reports to the Administrator, in a format prescribed by the Administrator. The reports would contain all of the data required concerning ozone season NO_X emissions.

For units exhausting to common stacks, 40 CFR part 75 includes options that often allow monitoring to be conducted at the common stack on a combined basis for all the units as an alternative to installing separate monitoring systems for the individual units in the ductwork leading to the common stack. The units then keep records and report hourly and cumulative NO_X mass emissions and in many cases heat input data on a combined basis for all units exhausting to the common stack. With respect to heat input data, but not NO_X mass emissions data, most such units are also required to record and report hourly and cumulative data on an individual-unit basis, and where necessary they typically compute the necessary unit-level hourly heat input values by apportioning the combined hourly heat input values for the common stack in proportion to the individual units' recorded hourly output of electricity or steam. *See generally* 40 CFR 75.72.

In this rulemaking, the proposed provisions governing default unit-level allowance allocations, backstop daily NO_X emissions rates for certain coal-fired units, and secondary emissions limitations for units contributing to assurance level exceedances would all require the use of unit-level reported data on NO_X mass emissions (or unit-level NO_X emissions rates computed in part based on unit-level reported data on NO_X mass emissions). To facilitate the implementation of these proposed provisions, the EPA is proposing to require all units covered by the Group 3 trading program exhausting to common stacks to record and report unit-level hourly and cumulative NO_X mass emissions data starting with the 2024 control period. To obtain the necessary unit-level hourly mass emissions values, the EPA proposes to allow the units to apportion hourly mass emissions values determined at the common stack in proportion to the individual units' recorded hourly heat input. The proposed apportionment procedure would be very similar to the apportionment procedure that most such units already apply to compute reported unit-level heat input data. Because the additional required data values would be obtained through apportionment, implementation of the proposed additional recordkeeping and reporting requirements would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75. In most cases, the EPA expects that the reported values computed through these apportionment procedures would reasonably approximate the values that could be obtained through installation and operation of separate monitoring systems for the individual units, because the units exhausting to the common stack would be expected to have similar NO_X emissions rates. However, the EPA also recognizes that at some plants, unit-level values determined through apportionment based on electricity or steam output could overstate the reported NO_X mass emissions for some units and correspondingly understate the reported NO_X mass emissions for other units. While the EPA has not at this time identified any reason to expect such potential overstatement and understatement to cause the proposed requirements in this rule to be less stringent overall, the Agency requests comment on whether units in particular situations should be required to obtain the necessary hourly mass emissions values through installation and operation of monitoring systems at the individual-unit level.[290]

In addition, to implement the proposed backstop daily NO_X emissions rates during the ozone season for certain coal-fired units, the EPA is proposing to require additional recordkeeping and reporting requirements for these units. Specifically, starting in 2024 for coal-fired units with existing SCR controls serving generators larger than 100 MW, and starting in 2027 for other coal-fired units serving generators larger than 100 MW (except circulating fluidized bed units), the units would be required to record and report total daily NO_X emissions and total daily heat input, daily average NO_X emissions rate, and daily NO_X emissions exceeding the applicable backstop daily NO_X emissions rates. The units would also be required to record and report cumulative NO_X emissions exceeding the backstop daily NO_X emissions rates for the ozone season. These data would be used to determine the allowance surrender requirements related to the backstop daily NO_X emissions rates. As with the additional recordkeeping and reporting requirements discussed above for units exhausting to common stacks, implementation of the additional recordkeeping and reporting requirements for coal-fired units would necessitate a one-time update to the units' data acquisition and handling systems but would not require any changes to the monitoring systems already needed to meet other requirements under 40 CFR part 75.

In states whose sources currently participate in the Group 3 trading program, as well as states whose sources participate in the Group 2 trading program and would transition to the

report required data on an ozone season-only basis. *See* 40 CFR 97.1034(d)(1); *see also* 40 CFR 75.74(a)–(b). Thus, for units that are required or elect to report other data on a year-round basis, the proposed additional recordkeeping and reporting requirements would also apply year-round, while for units that are allowed and elect to report other data on an ozone season-only basis, the proposed additional requirements would also apply for the ozone season only.

[290] For example, as noted in Section VII.B.7 of this proposed rule, there are currently five plants in the states covered by this proposal where SCR-equipped coal-fired units and non-SCR-equipped coal-fired units exhaust to common stacks. If the owners and operators of these plants choose to report apportioned NO_X mass emissions data in preference to installing and operating separate monitoring systems, the likely effect would be to overstate reported NO_X mass emissions for the SCR-equipped units and correspondingly understate reported NO_X mass emissions for the non-SCR equipped units. This would make compliance with the proposed backstop daily NO_X emissions rate more challenging for the SCR-equipped units. If the EPA does not require the owners and operators to install and operate separate monitoring systems for the individual units in a final rule in this rulemaking, the owners and operators would still have the option to do so if they believed it would be to their benefit.

Group 3 trading program under this proposal, units that are not subject to the proposed backstop daily NO_X emissions rates would not need to make any changes to their current monitoring and reporting as a result of the transition. The sources in states currently in the Group 2 trading program would be required to begin monitoring and reporting of NO_X emissions and operational data for purposes of the Group 3 trading program as of May 1, 2023, the start of the 2023 control period.

In states whose sources do not currently participate in the Group 2 trading program, any sources that currently report ozone season NO_X mass emissions according to 40 CFR part 75 to comply with SIP requirements and that are not subject to the proposed backstop daily NO_X emissions rates similarly would not need to make any changes to their current monitoring and reporting as a result of the transition. Other sources in these states that currently report SO_2 and NO_X emissions data according to 40 CFR part 75 under other CSAPR trading programs or the Acid Rain Program would not need to certify new monitoring systems for purposes of the Group 3 trading program but would need to update their monitoring plans and possibly update the software in their data acquisition and handling systems to compute certain additional values from the measurements that are already being recorded. All the sources in these states that already have monitoring systems certified under 40 CFR part 75 would be required to begin monitoring and reporting of NO_X emissions and operational data for purposes of the Group 3 trading program as of the later of May 1, 2023, or the effective date of the final rule.[291]

Finally, any sources that meet the applicability criteria of the Group 3 trading program and that do not currently report NO_X emissions data to the EPA under 40 CFR part 75 would need to certify new monitoring systems in accordance with part 75 before they would be required to monitor and report emissions for purposes of the Group 3 trading program. The units the EPA has been able to identify as potentially affected under this proposal that may need to certify new monitoring systems are listed in Table VII.B.3–1 (along with some other units that are potentially affected under this proposal and that already have certified monitoring systems). Because each of the listed units commenced commercial operation more than 180 days before the date when a final rule in this rulemaking would become effective, under the current Group 3 trading program regulations (*i.e.,* without the revisions proposed in this section), each unit's monitor certification deadline would generally be the effective date of the final rule. To ensure that the final rule does not impose monitor installation and certification requirements on these units before the effective date of the final rule, the EPA is proposing to revise the Group 3 trading program's monitor certification deadline provisions to establish a 180-day window for certification of the new monitoring systems after the effective date of a final rule in this rulemaking for units that do not already have monitoring systems certified under 40 CFR part 75, similar to the 180-day window already provided to units commencing commercial operation after (or less than 180 days before) the final rule's effective date. The 180th day for units in this situation would likely fall after the end of the 2023 ozone season, with the result that the certification deadline would be extended until May 1, 2024, the first day of the 2024 ozone season. Because the program's allowance holding requirements apply to a given unit only after that unit's monitor certification deadline, the units in this situation consequently would become subject to allowance holding requirements as of the 2024 ozone season rather than the 2023 ozone season.[292]

The EPA requests comment on the proposed revisions to the recordkeeping and reporting provisions in 40 CFR part 75 and the proposed establishment of a 180-day window for certification of new monitoring systems after the effective date of a final rule in this rulemaking for units that do not already have monitoring systems certified under 40 CFR part 75. As discussed above, with respect to units exhausting to common stacks, the EPA also requests comment on whether units in particular situations should be required to obtain hourly NO_X mass emissions values through installation and operation of monitoring systems at the individual-unit level instead of being allowed to obtain values for individual units through apportionment of the combined values for the units exhausting to the common stack.

11. Transitional Provisions

This section discusses several provisions that the EPA proposes to implement in order to address the transition of sources into the Group 3 trading program as revised. The purposes of the proposed transitional provisions are generally the same as the purposes of the analogous transitional provisions promulgated in the Revised CSAPR Update: First, accounting for the possibility that the effective date of a final rule in this rulemaking will fall after the starting date of the first affected ozone season (which in this case is, May 1, 2023); second, establishing an appropriately-sized initial allowance bank through the conversion of previously banked allowances; and third, preserving the intended stringency of the Group 2 trading program for the sources that will continue to be subject to that program.[293] However, the sources that would be participants in the revised Group 3 trading program under this proposal are transitioning from several different starting points—with some sources already in the Group 3 trading

[291] For units that currently report under 40 CFR part 75 only for annual programs and that use the optional low mass emissions methodology in 40 CFR 75.19, an additional consideration could arise. Specifically, eligibility to use the low mass emissions methodology for reporting ozone season NO_X mass emissions is restricted to units demonstrating that they have not exceeded or will not exceed a maximum of 50 tons of NO_X per ozone season. In theory, some units that would be eligible to use the low mass emissions methodology for purposes of annual programs only might lose that eligibility because of the 50-ton ozone season cap (which does not apply to units reporting for annual programs only). Based on the emissions reports submitted for the 2018–2020 control periods under the Acid Rain Program and the CSAPR annual programs, none of the existing units that currently report under 40 CFR part 75 for annual programs only and that would be added to the Group 3 trading program under the proposal are presently in this theoretical situation.

[292] Table VII.B.3–1 of this proposed rule lists 22 existing units in Delaware, Nevada, Utah, and Wyoming that appear to meet the Group 3 trading program's general applicability criteria and that do not already report NO_X emissions data to the EPA under 40 CFR part 75 pursuant to any other existing regulatory requirements. As noted in Section VII.B.3 of this proposed rule, six of the 22 listed units have reported that they may retire before the 2023 ozone season, and the possibility exists that up to nine of the remaining listed units could qualify for an exemption from the Group 3 trading program available to certain cogeneration units. EPA therefore projects that the revision to the monitor certification deadline proposed in this section, and the related delay in allowance holding requirements from 2023 to 2024, could apply to between seven and 22 units, with the total estimated 2021 ozone season NO_X emissions for all such units ranging between 250 and 450 tons. During the period before allowance holding requirements apply to the units—*i.e.,* the period from the effective date of a final rule in this rulemaking until the start of the 2024 control period—other requirements of the program would still apply, such as the requirement for submission of a certificate of representation by a designated representative and the requirements related to installation and certification of required monitoring systems.

[293] The EPA is not proposing to create a ''safety valve mechanism'' in this rulemaking analogous to the safety valve mechanism established under the Revised CSAPR Update.

program under its current regulations, some sources coming from the Group 2 trading program, and some sources not currently participating in any seasonal NO_X trading program. EPA is therefore proposing transitional provisions that differ across the sets of potentially affected sources based on the sources' different starting points.

a. Prorating Emissions Budgets, Assurance Levels, and Unit-Level Allowance Allocations in the Event of an Effective Date After May 1, 2023

While it is EPA's intent for a final rule in this rulemaking to take effect before the start of the Group 3 trading program's 2023 control period on May 1, 2023, it is possible that the final rule's effective date will fall after that date. The EPA proposes to address this contingency by determining the amounts of emissions budgets and unit-level allowance allocations on a full-season basis in the rulemaking and by also including provisions in the revised regulations to prorate the full-season amounts as needed to ensure that no sources become subject to new or more stringent regulatory requirements before the final rule's effective date.[294] Variability limits and assurance levels for 2023 would be computed using the appropriately prorated emissions budgets amounts, and unit-level allocations would also be prorated.[295]

As discussed in Section VII.B.2 of this proposed rule, in the case of states (and Indian country within the states' borders) whose sources do not currently participate in either the Group 2 trading program or the Group 3 trading program—Delaware, Minnesota, Nevada, Utah, and Wyoming—the sources would begin participating in the Group 3 trading program on the later of May 1, 2023, or the final rule's effective date. For these states, in the rulemaking the EPA would compute the full-season emissions budgets that would apply for the entire 2023 control period if the final rule becomes effective no later than May 1, 2023, and is therefore in effect for the entire 153-day control period from May 1, 2023, through September 30, 2023. If the final rule becomes effective after May 1, 2023, the EPA would determine prorated emissions budgets by multiplying each full-season emissions budget by the number of days from the rule's effective date through September 30, 2023, dividing by 153 days, and rounding to the nearest allowance. The prorated variability limits would be computed as 21 percent of the prorated emissions budgets, rounded to the nearest allowance, yielding prorated assurance levels that equal 121 percent of the prorated emissions budgets. To determine unit-level allocation amounts from the prorated emissions budgets, the EPA would determine full-season allocation amounts in the rulemaking and would determine preliminary prorated allocation amounts in the same manner as described for the emissions budgets previously. The preliminary prorated amounts of the largest unit-level allowance allocations for each state would then each be adjusted up or down by one allowance as needed to cause the sum of the final prorated unit-level allowance allocations for the state to equal the state's prorated emissions budget. All calculations required to determine the prorated emissions budgets and variability limits and the unit-level allocations for the 2023 control period would be carried out as soon as possible after the EPA learns the effective date of a final rule in this rulemaking (which is expected to be approximately 60 days after the date of the final rule's publication in the **Federal Register**). The unit-level allocations for both the 2023 and 2024 control periods would be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in Section VII.B.9.b of this proposed rule.

In the case of states (and Indian country within the states' borders) whose sources currently participate in the Group 3 trading program—Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia—the sources would continue to participate in the Group 3 trading program for the 2023 control period, subject to prorating procedures designed to ensure that the changes in 2023 emissions budgets and assurance levels would not substantively affect the sources' requirements prior to the rule's effective date. For these states, in the rulemaking the EPA would compute the full-season emissions budgets that would apply for the entire 2023 control period if the final rule becomes effective no later than May 1, 2023, but the EPA would not remove from the regulations the full-season emissions budgets for the 2023 control period that were established in the Revised CSAPR Update rulemaking. Instead, the EPA would include both sets of emissions budgets and variability limits in the regulations, along with a provision indicating that the emissions budgets promulgated in the Revised CSAPR Update would apply on a prorated basis for the portion of the 2023 control period before the final rule's effective date and the emissions budgets established in this rulemaking would apply on a prorated basis for the portion of the 2023 control period on and after the final rule's effective date. Under this provision, the EPA would determine a blended emissions budget for each state for the 2023 control period, computed as the sum of the appropriately prorated amounts of the state's current and revised emissions budgets. (For example, if the final rule became effective on the eleventh day of the 153-day 2023 control period, the blended emissions budget would equal the sum of 10/153 times the current emissions budget plus 143/153 times the revised emissions budget, rounded to the nearest allowance.) Blended variability limits for the 2023 control period would be computed as 21% of the blended emissions budgets, yielding blended assurance levels equal to 121 percent of the blended emissions budgets. Unit-level allocations would be determined by applying the allocation procedure described in Section VII.B.9 of this proposed rule to the blended budgets. In the case of states (and Indian country within the states' borders) whose sources currently participate in the Group 2 trading program—Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin—the sources would begin to participate in the Group 3 trading program as of May 1, 2023, regardless of the final rule's effective date, as discussed in Section VII.B.2 of this proposed rule, subject to prorating procedures designed to ensure that the transition from the Group 2 trading program to the Group 3 trading program would not substantively affect the sources' requirements prior to the rule's effective date. The prorating procedures for these states would mirror the procedures for the states currently in the Group 3 trading program, except that because no emissions budgets currently appear in the Group 3 trading program regulations for the states that are currently covered by the Group 2 trading program, the EPA would add two sets of emissions budgets for these states to the Group 3 trading program regulations: First, the states' emissions budgets for the 2023 control period that currently appear in the Group 2 trading

[294] As discussed in Sections VII.B.7 and VII.B.8 of this proposed rule, the proposed revisions establishing unit-specific backstop daily emissions rates and, for units contributing to assurance level exceedances, secondary unit-specific emissions limitations, would not take effect until the 2024 control period or later.

[295] The EPA notes that transitional provisions similar to the prorating provisions proposed in this section were finalized and implemented under the Revised CSAPR Update.

program regulations, which would be included in the revised Group 3 trading program regulations to represent the states' emissions budgets for the portion of the 2023 control period before the final rule's effective date, and second, the emissions budgets for the 2023 control period established for the states in this rulemaking, which would be included in the revised Group 3 trading program regulations to represent the state's emissions budgets for the portion of the 2023 control period on and after the final rule's effective date. The procedures for determining blended emissions budgets, variability limits and assurance levels, and unit-level allowance allocations would be the same as for the states currently in the Group 3 trading program. Again, all calculations required to determine the prorated emissions budgets and variability limits and the unit-level allocations for the 2023 control period would be carried out as soon as possible after the EPA learns the effective date of a final rule in this rulemaking (which is expected to be approximately 60 days after the date of the final rule's publication in the **Federal Register**). The unit-level allocations for both the 2023 and 2024 control periods would be recorded in facilities' compliance accounts approximately 30 days after the final rule's effective date, as discussed in Section VII.B.9.b of this proposed rule.

The reason for proposing that sources currently in the Group 2 trading program would begin to participate in the Group 3 trading program on May 1, 2023 even if the final rule's effective date is after May 1, 2023, is that it would serve the public interest and greatly aid in administrative efficiency for most elements of the Group 3 trading program—specifically, all elements of the trading program other than the elements designed to establish more stringent emissions limitations for the sources coming from the Group 2 trading program—to apply to the sources starting on May 1, 2023. This would facilitate implementation of the Group 3 trading program in an orderly manner for the entire 2023 ozone season and reduce compliance burdens and potential confusion. Each of the CSAPR trading programs for ozone season NO_X is designed to be implemented over an entire ozone season. Implementing the transition from the Group 2 trading program to the Group 3 trading program in a manner that required the covered sources to participate in the Group 2 trading program for part of the 2023 ozone season and the Group 3 trading program for the remainder of that ozone season would be complex and burdensome for sources. Attempting to address the issue by splitting the Group 2 and Group 3 requirements for these sources into separate years is not a viable approach, because EPA has no legal basis for releasing the transitioning Group 2 sources from the emissions reduction requirements found to be necessary in the CSAPR Update for a portion of the 2023 ozone season, and EPA similarly has no legal basis for deferring implementation of the 2023 emissions reduction requirements found to be necessary under this rule for the transitioning Group 2 sources until 2024. Moreover, the requirements of the current Group 2 trading program and the revised Group 3 trading program for the 2023 control period are substantively identical as to almost all provisions, such that with respect to those provisions, a source will not need to alter its operations in any manner or face different compliance obligations as a consequence of a transition from the Group 2 trading program to the Group 3 trading program. Thus, the EPA believes that no substantive concerns regarding retroactivity arise from transitioning the sources currently in the Group 2 trading program to the Group 3 trading program starting on May 1, 2023, as long as those aspects of the revised Group 3 trading program for the 2023 control period that *do* meaningfully differ from the analogous aspects of the Group 2 trading program—that is, the relative stringencies of the two trading programs, as reflected in the emissions budgets and associated assurance levels—are applied only as of the effective date of the final rule.

In all respects other than prorating the emissions budgets, variability limits and assurance levels, and unit-level allowance allocations, with respect to the sources currently participating in the Group 2 trading program or the Group 3 trading program, the EPA proposes to implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period. Thus, emissions would be monitored and reported for the entire 2023 ozone season (*i.e.,* May 1, 2023, through September 30, 2023), and as of the allowance transfer deadline for the 2023 control period (*i.e.,* June 1, 2024) each source would be required to hold in its compliance account vintage-year 2023 Group 3 allowances not less than the source's emissions of NO_X during the entire 2023 ozone season. Any efforts undertaken by one of these sources to reduce its emissions during the portion of the 2023 ozone season before the effective date of the rule would aid the source's compliance by reducing the amount of Group 3 allowances that the source would need to hold in its compliance account as of the allowance transfer deadline, increasing the range of options available to the source for meeting its compliance obligations under the revised Group 3 trading program. In the case of the sources that do not currently participate in the Group 2 trading program or the Group 3 trading program, the EPA similarly proposes to implement the revised Group 3 trading program for the 2023 control period in a uniform manner for the entire control period, except that the 2023 control period for these sources may be shorter than the normal 153-day length.

The EPA requests comment on this approach for implementing the Group 3 trading program in a manner that would apply the substantive increases in stringency of the emissions budgets and assurance levels established under the final rule on and after, but not before, the final rule's effective date.

b. Creation of Additional Group 3 Allowance Bank for 2023 Control Period

In the CSAPR Update, where the EPA established the Group 2 trading program and transitioned over 95% of the sources that had been participating in what is now the CSAPR NO_X Ozone Season Group 1 Trading Program (the ''Group 1 trading program'') to the new program, the EPA determined that it was reasonable to establish an initial bank of allowances for the Group 2 trading program by converting almost all allowances banked under the Group 1 trading program at a conversion ratio determined by a formula. In the Revised CSAPR Update, where EPA established the Group 3 trading program and transitioned approximately 55% of the sources that had been participating in the Group 2 trading program to the new program, the EPA similarly determined that it was reasonable to establish an initial bank of allowances for the Group 3 trading program by converting allowances banked under the Group 2 trading program at a conversion ratio determined by a formula, using a conversion procedure that was modified to leave much of the Group 2 allowance bank available for use by the approximately 45% of sources then in the Group 2 trading program that would remain in that program. Any conversion of banked allowances from a previous trading program for use in a new trading program must ensure that implementation of the new trading program will result in NO_X emissions reductions sufficient to address significant contribution by all states that would be participating in the new trading program, while also providing industry certainty (and obtaining an environmental benefit) through continued recognition of the value of saving allowances through early reductions in emissions. EPA's approach to balancing these concerns in the CSAPR Update through the conversion of banked allowances from the Group 1 trading program to the Group 2 trading program was upheld in *Wisconsin* v. *EPA,* see 938 F.3d at 321.

In the current rulemaking, applying the same balancing principle as in the CSAPR Update and the Revised CSAPR Update, the EPA proposes to carry out a further conversion of allowances banked for control periods before 2023 under the Group 2 trading program into allowances usable in the Group 3 trading program in control periods in 2023 and later years. Because the EPA is proposing to transition over 90% of the remaining sources in the Group 2 trading program to the Group 3 trading program—much closer to the situation in the CSAPR Update than the situation in the Revised CSAPR Update—in this rulemaking EPA proposes to apply a conversion procedure similar to the procedure followed in the CSAPR Update. Under the proposed conversion procedure, in the final rule in this rulemaking the EPA would not set a predetermined conversion ratio but instead would set provisions defining the types of accounts whose holdings of Group 2 allowances would be converted to Group 3 allowances and establishing the target amount of new Group 3 allowances that would be created. The proposed conversion date would be August 1, 2023, which is 2 months after the compliance deadline for the 2022 control period under the Group 2 trading program and ten months before the compliance deadline for the 2023 control period under the Group 3 trading program. The actual conversion ratio would be determined as of the conversion date and would be the ratio of the total amount of Group 2 allowances held in the identified types of accounts prior to the conversion to the total amount of Group 3 allowances being created. Consistent with the approach taken in the CSAPR Update, the EPA proposes to define the types of accounts included in the conversion to include all accounts except the facility accounts of sources in states that would remain in the Group 2 trading program.[296] Thus, the accounts whose holdings of Group 2 allowances would be converted to Group 3 allowances would include (1) the facility accounts of all sources in the states transitioning from the Group 2 trading program to the Group 3 trading program, (2) the facility accounts of all sources in the states already participating in the Group 3 trading program, (3) the facility accounts of all sources in any other states not covered by the Group 2 trading program that happen to hold Group 2 allowances as of the conversion date, and (4) all general accounts (that is, accounts that are not facility accounts, including other accounts controlled by source owners as well as accounts controlled by non-source entities such as allowance brokers). Creating the new Group 3 allowances through conversion of previously banked Group 2 allowances would also help preserve the stringency of the Group 2 trading program for the states that remain covered by that trading program at levels consistent with the stringency found to be appropriate to address those states' good neighbor obligations with respect to the 2008 ozone NAAQS in the CSAPR Update.

With respect to setting the target amount of Group 3 allowances that would be created in the conversion process, the EPA proposes to follow the same approach that was used in the Revised CSAPR Update for creation of the initial Group 3 allowance bank. Specifically, the target amount of Group 3 allowances to be created would be computed as the sum of the variability limits for the 2024 control period[297] established in the final rule for the states being transitioned to the Group 3 trading program from the Group 2 trading program, prorated to reflect the portion of the 2023 control period occurring on and after the effective date of the final rule. Based on the amounts of the proposed state emissions budgets and variability limits, the full-season target amount for the conversion would be 18,517 Group 3 allowances. The quantity of banked Group 2 allowances currently held in accounts other than the facility accounts of sources in Iowa and Kansas exceeding the quantity of allowances likely to be needed for 2021 compliance is approximately 110,000 allowances. If the quantities of banked Group 2 allowances did not change between now and the conversion date, and if there was no prorating adjustment, the conversion ratio would be approximately 5.9-to-1, meaning that one Group 3 allowance would be created for every 5.9 Group 2 allowances deducted in the conversion process.[298]

As noted in Section VII.B.11.a of this proposed rule, it is possible that the effective date of this rule will occur after the start of the 2023 ozone season, and provisions are being proposed to ensure that the increased stringency of this rule's state budgets and state assurance levels (*i.e.,* the sums of the budgets and variability limits) would take effect only after the rule's effective date. Consistent with these other procedures, the EPA is proposing to similarly prorate the bank target amount used in the conversion process. For example, if the effective date of the final rule is the eleventh day of the 153-day 2023 ozone season, the full-season initial bank target amount of 18,517 allowances would be prorated to an initial bank target amount of 17,307 allowances.[299] The EPA notes that prorating the bank amount in this manner would not reduce sources' compliance flexibility for the 2023 ozone season, because the amounts of Group 3 allowances that sources would receive for the portion of the 2023 ozone season before the rule's effective date would be based on the current trading program budgets for the 2023 control period before this rulemaking. The current trading program budgets exceed the sources' collective 2021 emissions by approximately 18,600 tons, indicating potentially surplus allowances roughly equal to the full-season bank conversion target amount of 18,517 allowances. Thus, although the prorating procedure would reduce the amount of Group 3 allowances that would be available to sources in the form of an initial bank, the reduction in the quantity of these allowances would be offset by the quantities of Group 3 allowances that would be allocated in excess of sources' recent historical emissions levels for the portion of the ozone season before the final rule's effective date.

As in the CSAPR Update and the Revised CSAPR Update, EPA's overall objective in establishing the target amount for the allowance conversion would be to achieve a total target amount for the bank at a level high enough to accommodate year-to-year

[296] If the proposed expansion of geographic scope for the Group 3 trading program is unchanged in the final rule, the states whose sources would continue to participate in the Group 2 trading program would be Iowa and Kansas.

[297] Similar to the approach taken in the Revised CSAPR Update, because emissions reductions from some of the emissions controls that EPA has identified as appropriate to use in setting budgets are first reflected in the 2024 state budgets rather than the 2023 state budgets, the EPA is proposing to base the bank target amount on the sum of the states' 2024 variability limits rather than the 2023 variability limits.

[298] By comparison, the analogous conversion ratio under the Revised CSAPR Update was 8-to-1.

[299] $18,517 \times (153 - 10) \div 153 = 17,307$.

variability in operations and emissions, as reflected in states' variability limits, but not high enough to allow sources collectively to plan to emit in excess of the collective state budgets. EPA believes that a well-established trading program would be able to function with an allowance bank lower than the full amount of the covered states' variability limits, as discussed in section VII.B.6 with respect to the proposed bank recalibration process that would begin with the 2024 control period. However, EPA also believes there are several compelling reasons in this instance to use a bank target higher than the minimum practicable level.

First, making an allowance bank available for use in the 2023 control period that is somewhat higher than the minimum practicable level would help to address concerns that might otherwise arise regarding the transition to a new set of compliance requirements, for some sources, and the transition to compliance requirements based on revised emissions budgets different from the emissions budgets that the sources had reason to anticipate under previous rulemakings, for the remaining sources. Although the EPA is confident that the emissions budgets being proposed in this rulemaking for the 2023 control period are readily achievable, the EPA also believes that the existence of a somewhat larger allowance bank at this transition point will promote sources' confidence in their ability to meet their 2023 compliance obligations in general and in a liquid allowance market in particular. Second, because the large majority of the remaining Group 2 allowances that would be converted to Group 3 allowances in this rulemaking are held by the sources currently in the Group 2 trading program, while the large majority of the initial bank of Group 3 allowances previously created in the conversion under the Revised CSAPR Update are held by the sources already in the Group 3 trading program, basing the conversion in this rulemaking on a target bank amount set in the same manner as the target bank amount used in the Revised CSAPR Update is expected to result in a less concentrated distribution of holdings of banked Group 3 allowances following the conversion than would be the case if a more stringent target bank amount were used under this rulemaking than was used in the Revised CSAPR Update. A lower concentration of holdings of banked Group 3 allowances would generally be expected to help ensure allowance market liquidity. Third, EPA considers it equitable to treat the sources in the states transitioning from the Group 2 trading program to the Group 3 trading program in this rulemaking roughly similarly to the sources in the states that transitioned between the same two trading programs in the Revised CSAPR Update with respect to the benefit they would receive under the Group 3 trading program for any efforts they may have made to make emissions reductions under the Group 2 trading program beyond the minimum efforts that were required to comply with the emissions budgets under that program. Finally, to the extent that the proposed conversion results in a larger bank of allowances remaining after the 2023 control period than is considered necessary to sustain a well-functioning trading program in subsequent control periods, the excess would be removed from the program in the proposed bank recalibration process that would be implemented starting with the 2024 control period and therefore would not weaken sources' incentives to control emissions on a permanent basis.

The EPA requests comment on the proposal to create additional banked Group 3 allowances through the conversion of Group 2 allowances banked for control periods before 2023.

c. Recall of Group 2 Allowances Allocated for Control Periods After 2022

To maintain the previously established levels of stringency of the Group 2 trading program for the states and sources that remain subject to that program under this proposed rule, the EPA proposes to recall CSAPR NO_X Ozone Season Group 2 allowances equivalent in amount and usability to all vintage year 2023–2024 CSAPR NO_X Ozone Season Group 2 allowances previously allocated to sources in Group 3 states and areas of Indian country and recorded in the sources' compliance accounts. The proposed recall provisions would apply to all sources in jurisdictions newly added to the Group 3 trading program in whose compliance accounts CSAPR NO_X Ozone Season Group 2 allowances for a control period in 2023 or 2024 were recorded, including sources where some or all units have permanently retired or where the previously recorded 2023–2024 allowances have been transferred out of the compliance account. The proposed recall provisions provide a flexible compliance schedule intended to accommodate any sources that have already transferred the previously recorded 2023–2024 allowances out of their compliance accounts and allows Group 2 allowances of earlier vintages to be surrendered to achieve compliance. Like the similar recall provisions finalized in the Revised CSAPR Update, the proposed recall provisions include specifications for how the recall provisions apply in instances where a source and its allowances have been transferred to different parties and for the procedures that the EPA will follow to implement the recall.

Under the Group 2 trading program regulations, each Group 2 allowance is a ''limited authorization to emit one ton of NO_X during the control period in one year,'' where the relevant limitations include the EPA Administrator's authority ''to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.'' 40 CFR 97.806(c)(6)(ii). The Administrator proposes to determine that, in order to effectively implement the Group 2 trading program as a compliance mechanism through which states not subject to the Group 3 trading program may continue to meet their obligations under CAA section 110(a)(2)(D)(i)(I) with regard to the 2008 ozone NAAQS, it is necessary to limit the use of Group 2 allowances equivalent in quantity and usability to all Group 2 allowances previously allocated for the 2023–2024 control periods and recorded in the compliance accounts of sources in the newly added Group 3 jurisdictions. The Group 2 allowances that have already been allocated to sources in the newly added Group 3 states for the 2023–2024 control periods and recorded in the sources' compliance accounts represent the substantial majority of the total remaining quantity of Group 2 allowances that have been allocated and recorded for the 2023–2024 control periods and that were not already made subject to recall when other jurisdictions were transferred from the Group 2 trading program to the Group 3 trading program in the Revised CSAPR Update. Because allowances can be freely traded, if the use of the 2023–2024 Group 2 allowances previously recorded in newly added Group 3 sources' compliance accounts (or equivalent Group 2 allowances) were not limited, the effect would be the same as if the EPA had issued to sources in the states that will remain covered by the Group 2 trading program a quantity of allowances available for compliance under the 2023–2024 control periods many times the levels that the EPA determined to be appropriate emissions budgets for these states in the CSAPR Update. Through the use of banked allowances, the excess Group 2 allowances would affect compliance under the Group 2 trading program in control periods after 2024 as well. Continued implementation of the Group 2 trading program at levels of stringency consistent with the levels contemplated under the CSAPR Update therefore requires that the EPA limit the use of the excess allowances, as the EPA is proposing here.

In this rulemaking, the EPA proposes to implement limitations on the use of the excess 2023–2024 Group 2 allowances through requirements to surrender, for each 2023–2024 Group 2 allowance recorded in a newly added Group 3 source's compliance account, one Group 2 allowance of equivalent usability under the Group 2 trading program. The surrender requirements would apply to the owners and operators of the Group 3 sources in whose compliance account the excess 2023–2024 Group 2 allowances were initially recorded. In general, each source's current owners and operators would be required to comply with the surrender requirements for the source by ensuring that sufficient allowances to complete the deductions are available in the source's compliance account by one of two possible deadlines discussed below. However, an exception would be provided if a source's current owners and operators obtained ownership and operational control of the source in a transaction that did not include rights to direct the use and transfer of some or all of the 2023–2024 Group 2 allowances allocated and recorded (either before or after that transaction) in the source's compliance account. The proposed rule provides that in such a circumstance, with respect to the 2023–2024 Group 2 allowances for which rights were not included in the transaction, the surrender requirements would apply to the most recent former owners and operators of the source before any such transactions occurred. Because in this situation a source's former owners and operators might lack the ability to access the source's compliance account for purposes of complying with the surrender requirements, the former owners and operators would instead be allowed to meet the surrender requirements with Group 2 allowances held in a general account.[300]

To provide as much flexibility as possible consistent with the need to limit the use of the excess Group 2 allowances, for each 2023–2024 Group 2 allowance recorded in a Group 3 source's compliance account, the EPA proposes to accept the surrender of either the same specific 2023–2024 Group 2 allowance or any other Group 2 allowance with equivalent (or greater) usability under the Group 2 trading program. Thus, a surrender requirement with regard to a Group 2 allowance allocated for the 2023 control period could be met through the surrender of any Group 2 allowance allocated for the 2023 control period or the control period in any earlier year—in other words, any 2017–2023 Group 2 allowance.[301] Similarly, the surrender requirement with regard to a 2024 Group 2 allowance could be met through the surrender of any 2017–2024 Group 2 allowance.

Owners and operators subject to the surrender requirements could choose from two possible deadlines for meeting the requirements. The first deadline would be 15 days after the effective date of a final rule in this rulemaking.[302] As soon as practicable or after this date, the EPA would make a first attempt to complete the deductions of Group 2 allowances required for each Group 3 source from the source's compliance account. The EPA would deduct Group 2 allowances first to address any surrender requirements for the 2023 control period and then to address any surrender requirements for the 2024 control period. When deducting Group 2 allowances to address the surrender requirements for each control period, EPA would first deduct allowances allocated for that control period and then would deduct allowances allocated for each successively earlier control period. This order of deductions is intended to ensure that whatever Group 2 allowances are available in the account are applied to the surrender requirements in a manner that both maximizes the extent to which all of the source's surrender requirements would be met and also ensures that any Group 2 allowances left in the source's compliance account after completion of all required deductions would be the earliest allocated, and therefore most useful, Group 2 allowances possible. Among the Group 2 allowances allocated for a given control period, The EPA would first deduct allowances that were initially recorded in that account, in the order of recordation, and would then deduct allowances that were transferred into that account after having been initially recorded in some other account, in the order of recordation.

Following the first attempt to deduct Group 2 allowances to address Group 3 sources' surrender requirements, the EPA would send a notification to the designated representative for each such source (as well as any alternate designated representative) indicating whether all required deductions were completed and, if not, the additional amounts of Group 2 allowances usable in the 2023 or 2024 control periods that must be held in the appropriate account by the second surrender deadline of September 15, 2023. Each notification would be sent to the email addresses most recently provided to the EPA for the recipients and would include information on how to contact the EPA with any questions. The EPA proposes that no allocations of Group 3 allowances would be recorded in a source's compliance account until all the source's surrender requirements with regard to 2023–2024 Group 2 allowances have been met. For this reason, the principal consequence to a source of failure to fully comply with the surrender requirements by 15 days after the effective date of a final rule would be that any Group 3 allowances allocated to the units at the source for the 2023 and 2024 control periods that would otherwise have been recorded in the source's compliance account by 30 days after the effective date of a final rule would not be recorded as of that recordation date.

If all surrender requirements of 2023–2024 Group 2 allowances for a source have not been met in EPA's first attempt, the EPA would make a second attempt to complete the required deductions from the source's compliance account (or from a specified general account, in the limited circumstance noted above) as soon as practicable on or after September 15, 2023. The order in which Group 2 allowances are deducted would be the same as described above for the first attempt.

If the second attempt to deduct Group 2 allowances to meet the surrender requirements through deductions from the source's compliance account (or

[300] The EPA is currently unaware of any source that would need to use this flexibility but has included the option in the proposal to address the theoretical possibility of such a situation.

[301] The first control period for the Group 2 trading program was in 2017.

[302] As discussed later in this section and in Section VII.B.9.b, the EPA is proposing to condition recordation of any allocations of Group 3 allowances in a source's compliance account on the source's prior compliance with the proposed recall requirements for Group 2 allowances. The purpose of providing a first deadline for the recall provisions 15 days after a final rule's effective would be to ensure that sources have an early opportunity to comply with the recall provisions in order to be eligible to have allocations of Group 3 allowances recorded in their accounts as proposed 30 days after the final rule's effective date. Because the vast majority of sources subject to the proposed recall provisions already hold sufficient Group 2 allowances to comply with the recall provisions, the EPA anticipates that the sources would easily be able to comply with the proposed first recall deadline.

from a specified general account) is unsuccessful for a given source, the EPA proposes that as soon as practicable on or after November 15, 2023, to the extent necessary to address the unsatisfied surrender requirements for the source, the EPA would deduct the 2023–2024 Group 2 allowances that were initially recorded in the source's compliance account from whatever accounts the allowances are held in as of the date of the deduction, except for any allowances where, as of April 1, 2022, no person with an ownership interest in the allowances was an owner or operator of the source, was a direct or indirect parent or subsidiary of an owner or operator of the source, or was directly or indirectly under common ownership with an owner or operator of the source.[303] Before making any deduction under this provision, the EPA would send a notification to the authorized account representative for the account in which the allowance is held and would provide an opportunity for submission of objections concerning the data upon which the EPA is relying. In EPA's view, this provision would not unduly interfere with the legitimate expectations of participants in the allowance markets because the provision would not be invoked in the case of any allowance that was transferred to an independent party in an arms-length transaction before EPA's intent to recall 2023–2024 Group 2 allowances became widely known. The provision would apply only to a Group 2 allowance that, as of April 1, 2022, was still controlled either by the owners and operators of the source in whose compliance account it was initially recorded or by an entity affiliated with such an owner or operator. The EPA believes that by April 1, 2022, all market participants will have had ample opportunity to become informed of the proposed rule provisions to recall 2023–2024 Group 2 allowances recorded in Group 3 sources' compliance accounts, particularly since the EPA implemented a closely analogous recall of Group 2 allowances in the Revised CSAPR Update.[304]

The EPA proposes that failure of a source's owners and operators to comply with the surrender requirements would be subject to possible enforcement as a violation of the CAA, with each allowance and each day of the control period constituting a separate violation.

To eliminate any possible uncertainty regarding the amounts of Group 2 allowances allocated for the 2023–2024 control periods (or earlier control periods) that the owners and operators of each Group 3 source would be required to surrender under the recall provisions, the EPA has prepared a list of the sources in the proposed additional Group 3 states and areas of Indian country in whose compliance accounts allocations of 2023–2024 Group 2 allowances were recorded, with the amounts of the allocations recorded in each such compliance account for the 2023 and 2024 control periods. An additional list shows, for each newly added Group 3 source, the specific Group 2 allowances (batched by serial number) allocated for each control period and recorded in the source's compliance account and indicates whether, as of December 31, 2021, that batch of allowances was held in the source's compliance account, in an account believed to be partially or fully controlled by a related party (*i.e.,* an owner or operator of the source or an affiliate of an owner or operator of the source), or in an account believed to be fully controlled by independent parties. The lists are in a spreadsheet titled, ''Recall of Additional CSAPR NO_X Ozone Season Group 2 Allowances'', available in the docket for this proposed rule. After the first and second surrender deadlines, the EPA intends to update the lists to indicate for each Group 3 source whether the surrender requirements for the source under the recall provisions have been fully satisfied. The EPA would post the updated lists on a publicly accessible website to ensure that all market participants have the ability to determine which specific 2023–2024 Group 2 allowances initially recorded in any given Group 3 source's compliance account do or do not remain subject to potential deduction to address the source's surrender requirements under the recall provisions.

The EPA requests comment on the proposal to recall Group 2 allowances equivalent in quantity and usability to the Group 2 allowances previously issued for the 2023 and 2024 control periods and recorded in the compliance accounts of sources in jurisdictions being newly added to the Group 3 trading program in this proposed rule.

12. Conforming Revisions to Other Regulations

As noted in Section VII.B.1.a of this proposed rule, in addition to the Group 3 trading program, EPA currently administers five other CSAPR trading programs, all of which have provisions that in most respects parallel the provisions of the Group 3 trading program.[305] The EPA also administers the Texas SO_2 Trading Program, whose provisions parallel the provisions of the CSAPR trading programs to a somewhat lesser extent.[306] In this rulemaking, in addition to the proposed revisions to the Group 3 trading program, the EPA is proposing a small number of conforming revisions to the other CSAPR trading programs and/or the Texas SO_2 Trading Program to maintain consistency across the regulations for the various trading programs to the extent possible.

The first set of proposed conforming revisions concerns the use of the term ''Indian country'' in the allowance allocation provisions of the regulations for all the CSAPR trading programs. As discussed in Section VII.B.9.a of this proposed rule, to reflect the D.C. Circuit's holding in *ODEQ* v. *EPA* that states have initial CAA implementation planning authority in non-reservation areas of Indian country until displaced by a demonstration of tribal jurisdiction over such an area, the EPA is proposing to revise the allowance allocation provisions in the Group 3 trading program regulations so that, instead of distinguishing between the sets of units within a given state's borders that either are not or are in Indian country, the revised regulations would distinguish between (1) the set of units within the state's borders that are not in Indian country or are in areas of Indian country covered by the state's CAA implementation planning authority and (2) the set of units within the state's borders that are in areas of Indian country not covered by the state's CAA implementation planning authority. For the same reasons stated in Section VII.B.9.a of this proposed rule for the

[303] The proposed provision under which the EPA would not deduct Group 2 allowances transferred to unrelated parties before April 1, 2022 from the transferees' accounts would not relieve the source to which the Group 2 allowances were originally allocated from the obligation to comply with the recall requirements. Specifically, the source would be required to comply with the recall requirements by obtaining and surrendering other Group 2 allowances.

[304] Even before publication of the proposed rule, the EPA posted information on its websites to notify market participants that a pending rulemaking could have consequences for the value and usability of Group 2 allowances. The posted locations included the electronic portal that authorized account representatives use to enter allowance transfers for recordation by the EPA in the Allowance Management System. Additionally, the EPA emailed a notice identifying the possibility of such consequences to the representatives for all Allowance Management System accounts.

[305] The regulations for the Group 3 Trading Program are at 40 CFR 97, subpart GGGGG. The regulations for the other five CSAPR trading programs are at 40 CFR part 97, subparts AAAAA, BBBBB, CCCCC, DDDDD, and EEEEE.

[306] The regulations for the Texas SO_2 Trading Program are at 40 CFR part 97, subpart FFFFF.

Group 3 trading program, the EPA proposes to make revisions to the allowance allocation provisions in the regulations for all the other CSAPR trading programs establishing the same substantive distinction among the sets of units within each state's borders. The specific regulatory provisions that would be affected are identified in Section X of this proposed rule. The EPA is unaware of any currently operating units that would be affected by this proposed revision to the regulations for the other CSAPR trading programs.

The second set of proposed conforming revisions concerns the schedule for recording allocations of allowances to existing units. To maintain consistency with the provisions of the revised Group 3 Trading Program to the extent possible, the EPA proposes to revise the regulations for each of the other five CSAPR trading programs and the Texas SO_2 Trading Program to reflect whatever revised schedule for recording most allowance allocations the EPA may adopt for the revised Group 3 trading program in a final rule in this rulemaking. The proposed revisions to the recordation deadlines would affect only the timing of recordation, not the amounts of allowances allocated to and recorded for any source for any control period.

The effect of the proposed revisions would be to establish a new common recordation schedule for all the CSAPR trading programs and the Texas SO_2 Trading Program. Assuming the common schedule adopted is the specific schedule proposed for the Group 3 trading program in Section VII.B.9 of this proposed rule, allocations from the portion of each state emissions budget under each program not reserved in a set-aside would be recorded by July 1 of the year immediately preceding the year of the relevant control period. Under the current regulations before the proposed revisions, the equivalent recordation deadline is July 1 of the year three years before the year of the relevant control period. Relatedly, the EPA also proposes to revise the deadline for states to submit any state-determined allocations to the EPA under each trading program to June 1 of the year immediately preceding the year of the relevant control period, instead of June 1 of the year three years before the year of the relevant control period.[307]

This EPA believes that revising the recordation schedules as proposed to establish a new common recordation schedule for the affected trading programs would make the programs procedurally more consistent, generally reducing the time and cost expended by sources to understand and comply with multiple trading programs. Greater consistency across the various programs would also support greater administrative efficiency by the EPA and by states that elect to determine allowances allocations under the various programs. In addition, by reducing the number of future control periods for which allowances are recorded, the proposed revisions would reduce the likelihood that the EPA might need to recall already-recorded allowances as part of a transition for some sources to new regulatory requirements in a future rulemaking. The EPA has implemented such a recall in the Revised CSAPR Update and has proposed to implement a similar recall in this rulemaking.

Finally, the EPA believes that revising the recordation schedules for the other CSAPR trading programs and the Texas SO_2 Trading Program as proposed would not adversely impact allowance market liquidity. Allowances issued for control periods through 2024 under each of these programs were recorded by July 1, 2020. As of December 2021, although recorded private transfers of earlier vintage allowances usable for 2021 compliance have been increasing in advance of the upcoming June 1, 2022, compliance deadline for the 2021 control periods, few allowances recorded for the 2023 or 2024 control periods (or even the 2022 control period) under any of the programs have been transferred out of the accounts in which they were initially recorded, except as needed to comply with the recall of certain allowances under the Revised CSAPR Update. Moreover, most of the recorded transfers of allowances issued for 2022, 2023, and 2024 have been between accounts controlled by the same entity, corporate affiliates, or other related entities (such as unit co-owners) rather than between accounts controlled by unrelated parties. The EPA therefore believes there would have been little effect on arms-length allowance market activity in these programs if the proposed revised recordation schedule had already been in effect and the allowances for 2023 and 2024 consequently had not yet been recorded.

Further details on the specific regulatory provisions that would be affected by the proposed revisions to allowance allocation recordation schedules are provided in Section X of the proposed rule.

The EPA requests comment on the proposed revision to the definition of ''Indian country'' under the CSAPR NO_X Annual, NO_X Ozone Season Group 1, SO_2 Group 1, SO_2 Group 2, and NO_X Ozone Season Group 2 Trading Programs and the proposed revisions to the allowance allocation recordation deadlines under the CSAPR NO_X Annual, NO_X Ozone Season Group 1, SO_2 Group 1, SO_2 Group 2, and NO_X Ozone Season Group 2 Trading Programs and the Texas SO_2 Trading Program.

C. Regulatory Requirements for Non-EGUs

The EPA is proposing that the FIPs for 23 of the states covered in this proposed rule will include new emissions limitations on emissions units in seven non-EGU industries that EPA finds (as discussed in Section VI of this proposed rule) to be significantly contributing to nonattainment or interfering with maintenance in other states.

In order to achieve the necessary non-EGU emissions reductions for the 23 states, the EPA proposes emissions limitations for the most impactful units in the relevant industries that are achievable with the control technologies identified in the Step 3 analysis. The EPA is proposing a direct control approach with rate-based limits, production-based limits, and work practice standards set on a uniform basis for the different segments of non-EGU emissions units using applicability criteria based on size and type of unit and, in some cases, emissions thresholds. The EPA believes this approach can achieve the requisite level of emissions reductions from the covered units through the assignment of emissions limits that are achievable across the entire segment. The EPA believes that establishing emissions limits for emissions units based on size and type of unit and, in some cases, emissions thresholds, will achieve the necessary reductions without requiring a unit-by-unit assessment.[308] By

[307] The regulations for the various programs already establish a common recordation schedule for the portion of each state emissions budget set aside for possible allocation to new units—namely, by May 1 of the year after the year of the relevant control period. The related deadline for states to submit any state-determined allocations of these allowances to the EPA under each program is April 1 of the year after the year of the relevant control period.

[308] If an emissions unit installs SCR or SNCR to meet an emissions limit in response to the proposed FIP that would be a physical change under new source review (NSR) and lead to an assessment of potential emissions changes. If the installation of SCR results in an emissions increase that exceeds the thresholds in the NSR regulations for one or more regulated NSR pollutants, including the

establishing uniform emissions limits for categories of units rather than on a unit-by-unit basis, the EPA can also ensure that any new source of emissions constructed after this proposed rulemaking are also subject to the emissions limits identified later (*see* Section IV.B.1.d of this proposed rule).

The EPA recognizes that the numerous variables that contribute to differences in units' emissions rates may complicate development of limits for groups of units as large as those addressed in this proposed rule. For each emissions source category, the EPA considered the range of emissions limits that currently apply to these sources under other CAA programs, such as RACT, NSPS, NESHAP, and OTC model rules, to develop an emissions limit that should be achievable by all sources after installing the controls identified in the Step 3 analysis. For a detailed discussion of the technical bases for EPA's proposed requirements for non-EGU emissions units, see the Non-EGU Sectors TSD.

The EPA is proposing that the emissions limits and compliance requirements for non-EGUs will apply only during the ozone season (which runs annually from May–September). This is consistent with EPA's prior practice in federal actions to eliminate significant contribution of ozone in the 1998 NO_X SIP Call, CAIR, CSAPR, CSAPR Update, and the Revised CSAPR Update. EPA is seeking comment on whether non-EGU sources would run controls that would be installed as a result of this proposed FIP year-round (*i.e.,* will some source categories run their controls year-round due to the nature of those controls?).

In addition, the EPA proposes to apply the FIP requirements to all existing emissions units and any future emissions units constructed after the promulgation of a final rule. Further, the non-EGU emissions limits and compliance requirements will apply in all 23 states (and, as discussed in Section IV.C.2 of this proposed rule, in areas of Indian country within the borders of those states), even if some of those states do not currently have emissions units in a particular source category. This approach will ensure that all new sources constructed in any of the 23 states will be subject to the same regulatory requirements as applied for the existing units under this proposed rule. This will also mitigate any potential incentive to move production from an existing non-EGU source in one linked state to a new non-EGU source of the same type but lacking the relevant emissions control requirements in another linked state.

At this time, this EPA is not proposing to include non-EGUs in the trading program described in this proposed rule. If EPA were to include non-EGUs in the trading program, we would require monitoring and reporting of hourly mass emissions in accordance with 40 CFR part 75 as we have required for all trading programs. Monitoring and reporting under part 75 include CEMS (or an approved alternative method), rigorous initial certification testing, and periodic quality assurance testing thereafter, such as relative accuracy test audits and daily calibrations. This type of consistent and accurate measurement of emissions is necessary to ensure each allowance actually represents one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton of reported emissions from another source. *See* 75 FR 45325 (August 2, 2010). Moreover, these monitoring requirements generally would need to be in place for at least one full ozone season to establish baseline data before it would be appropriate to rely on a trading program as the mechanism to achieve the required emissions reductions. Therefore, at this time, the EPA believes that applying unit-level emissions limitations on non-EGU emissions units rather than constructing an emissions trading regime is more administratively feasible and more easily implementable at the source level, and it will effectively eliminate each state's significant contribution without the need for establishing a new emissions trading program.

The EPA is proposing to require electronic reporting for all seven non-EGU industries. Specifically, owners and operators of affected units must submit electronic copies of required performance test reports, performance evaluation reports, quarterly and semi-annual reports, and excess emissions reports through EPA's Central Data Exchange (CDX) using the Compliance and Emissions Data Reporting Interface (CEDRI). The EPA is proposing to require that performance test results collected using test methods that are supported by EPA's Electronic Reporting Tool (ERT) as listed on the ERT website [309] at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and that other performance test results be submitted in portable document format (PDF) using the attachment module of the ERT. Similarly, the EPA is proposing to require that performance evaluation results of CEMS measuring relative accuracy test audit (RATA) pollutants that are supported by the ERT at the time of the test be submitted in the format generated through the use of the ERT or an electronic file consistent with the xml schema on the ERT website, and that other performance evaluation results be submitted in PDF using the attachment module of the ERT. In addition, the EPA is proposing to require that quarterly and semi-annual reports and excess emissions reports be submitted in PDF uploaded in CEDRI.

The EPA is proposing to allow for an extension of time to file a report where an owner or operator demonstrates that it cannot meet the reporting deadline for reasons outside of its control. Specifically, the EPA has identified two broad circumstances under which the EPA may grant a request for an extension of time to file an electronic report. These circumstances are (1) outages of EPA's CDX or CEDRI which preclude an owner or operator from accessing the system and submitting required reports and (2) *force majeure* events, which are defined as events that will be or have been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevent an owner or operator from complying with the requirement to submit a report electronically. Examples of *force majeure* events are acts of nature, acts of war or terrorism, or equipment failure or safety hazards beyond the control of the facility. In both circumstances, the decision to grant an extension of time to report is within the discretion of the Administrator, and reporting should occur as soon as possible.

Electronic submittal of required reports will increase the usefulness of the data contained in those reports, is in keeping with current trends in data availability and transparency, will further assist in the protection of public health and the environment, will improve compliance by facilitating the ability of regulated facilities to demonstrate compliance with requirements and by facilitating the ability of the EPA to assess and determine compliance, and will ultimately reduce burden on regulated facilities and the EPA. Electronic reporting also eliminates paper-based, manual processes, thereby saving time and resources, simplifying data entry, eliminating redundancies, minimizing

netting analysis, the changes would trigger the applicability of NSR.

[309] *https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert.*

data reporting errors, and providing data quickly and accurately to the affected facilities, air agencies, EPA, and the public. Moreover, electronic reporting is consistent with EPA's plan [310] to implement Executive Order 13563 and is in keeping with EPA's agency-wide policy [311] developed in response to the White House's Digital Government Strategy.[312]

The EPA notes that no emissions standard or other requirement established for non-EGUs in these FIPs may be interpreted, construed, or applied to diminish or replace the requirements of any emissions limitation or other applicable requirement established by the Administrator pursuant to other CAA authority or a standard issued under State authority.

1. Pipeline Transportation of Natural Gas

Applicability

The EPA is proposing to establish regulatory requirements for the Pipeline Transportation of Natural Gas industry that apply to stationary, natural gas-fired, spark ignited reciprocating internal combustion engines (''stationary SI engines'') within these facilities that have a maximum rated capacity of 1,000 horsepower (hp) or greater. Based on our review of the potential emissions from stationary SI engines, we find that use of a maximum rated capacity of 1,000 hp reasonably approximates the selection of 100 tpy used within the non-EGU screening assessment. Therefore, stationary SI engines subject to the proposed rule requirements of this section are those found within any of the 23 covered states with non-EGU emissions reduction obligations that are within the Pipeline Transportation of Natural Gas industry and have a maximum rated capacity of 1,000 hp or greater.

Emissions Limitations and Rationale

In developing the emissions limits for the Pipeline Transportation of Natural Gas industry, EPA reviewed RACT NO_X rules, air permits, and OTC model rules. While some permits and rules express engine emissions limits in parts per million by volume (pmmv), the majority of rules and source-specific requirements express the emissions limits in grams per horsepower per hour (g/hp-hr). The EPA has historically set emissions limits for these types of engines using g/hp-hr and finds that method appropriate for this proposed FIP as well.

Based on the available information for this industry, applicable State and local air agency rules, and active air permits issued to sources with similar engines, the EPA is proposing the following emissions limits for stationary SI engines in the covered states:

TABLE VII.C–1—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR PIPELINE TRANSPORTATION OF NATURAL GAS

Engine type and fuel	Proposed NO_X emissions limit	Additional information
Natural Gas Fired Four Stroke Rich Burn	1.0 g/hp-hr	Limits reviewed ranged between 0.2 and 3.0 g/hp-hr.
Natural Gas Fired Four Stroke Lean Burn	1.5 g/hp-hr	Limits reviewed ranged between 0.5 and 3.0 g/hp-hr.
Natural Gas Fired Two Stroke Lean Burn	3.0 g/hp-hr	Limits reviewed ranged between 0.5 and 3.0 g/hp-hr.

With regard to four stroke rich burn engines, the EPA is proposing an emissions limit of 1.0 g/hp-hr. This limit is designed to be achievable by installing Non-Selective Catalytic Reduction (NSCR) on existing four stroke rich burn engines, as identified in the non-EGU screening assessment. Sources are free to install another control technology besides NSCR as long as the unit is still able to meet the emissions limit. In particular for four stroke rich burn engines, NSCR can be an effective control technology due to the low oxygen percentage in the exhaust. Efficient operation of the catalyst in NSCR requires the engine exhaust gases contain no more than 0.5 percent oxygen, which makes rich burn engines uniquely suitable to NCSR. Given that NSCR can achieve NO_X reductions of 90 to 99 percent, the EPA believes an emissions limit of 1.0 g/hp-hr should be readily achievable by all four stroke rich burn engines subject to this proposed rulemaking. The EPA is taking comment on whether a lower emissions limit is more appropriate since even an assumed reduction of 95 percent would result in most engines being able to achieve an emissions rate of 0.5 g/hp-hr. However, at this time, the EPA does not have the information necessary to determine if a lower emissions limit is achievable for the four stroke rich burn engines subject to the proposed rulemaking, and therefore, the EPA is proposing an emissions limit of 1.0 g/hp-hr.

With regard to four stroke lean burn engines, the EPA is proposing an emissions limit of 1.5 g/hp-hr. This limit is designed to be achievable by installing SCR on existing four stroke lean burn engines. Sources are free to install another control technology with or without SCR as long as the unit is still able to meet the emissions limit. For example, it might be more cost effective on an ongoing basis for some four stroke lean burn engines to install layered combustion controls alone or along with SCR to achieve the necessary emissions reductions. Information available to the EPA suggests that some four stroke lean burn engines can achieve 90% reductions from layered combustion controls alone, such as turbochargers and inter-cooling, pre-chamber ignition or high energy ignition, improved fuel injection control, air/fuel ratio control.[313] Independent of unit specific considerations, the EPA believes that four stroke lean burn engines subject to this proposed FIP can achieve an emissions limit of 1.5 g/hp-hr with the installation and operation of SCR or other control technologies at the marginal cost threshold of $7,500 per

[310] EPA's Final Plan for Periodic Retrospective Reviews, August 2011. Available at: *https://www.regulations.gov/document?D=EPA-HQ-OA-2011-0156-0154.*

[311] E-Reporting Policy Statement for EPA Regulations, September 2013. Available at: *https://www.epa.gov/sites/production/files/2016-03/documents/epa-ereporting-policy-statement-2013-09-30.pdf.*

[312] Digital Government: Building a 21st Century Platform to Better Serve the American People, May 2012. Available at: *https://obamawhitehouse.archives.gov/sites/default/files/omb/egov/digital-government/digital-government.html.* For more information on the benefits of electronic reporting, see the memorandum *Electronic Reporting Requirements for New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAP) Rules,* referenced earlier in this section.

[313] Ozone Transport Commission, *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions,* 35–39, October 17, 2012.

ton identified in the non-EGU screening assessment. While a lower emissions limit may be achievable with SCR for some four stroke lean burn engines, the achievability of those lower limits may depend on engine age and come with increased costs not accounted for in this proposed rule. The EPA is seeking comment on whether a lower and higher emissions limit is appropriate for these units.

For two stroke lean burn engines, the EPA is currently proposing an emissions limit of 3.0 g/hp-hr. This limit is designed to be achievable by retrofitting existing two stroke lean burn engines with layered combustion to achieve this emissions limit. Sources are free to install another control technology besides layered combustion as long as the unit is still able to meet the emissions limit. As identified in the non-EGU screening assessment, the EPA believes that layered combustion controls, such as improved airflow, improved fuel to air mixing, improved ignition, and modern engine electronic controls can be achieved on two stroke engines at the marginal cost threshold of $7,500 per ton. With these types of controls, the information currently available to the EPA indicates that the amount of achievable emissions reductions is unit specific and can range from a 60 to 90 percent reduction in NO_X emissions. The EPA estimates that existing uncontrolled two stroke lean burn engines would need to reduce emissions by about 80 percent to comply with a 3.0 g/hp-hr emissions limit. While some RACT and model rules reviewed contained more stringent emissions limits for two stroke lean burn engines, the EPA does not have information adequate to conclude that the two stroke lean burn engines across all 23 states can meet a lower limit. Further, some information available supports a finding that an emissions limit below 3.0 g/hp-hr might not be achievable with layered combustion controls alone for some units, and those units would require additional controls beyond our cost threshold.[314] Therefore, the EPA is proposing an emissions limit of 3.0 g/bhp-hr for two stroke engines. The EPA is seeking comment on whether a lower emissions limit would be achievable with layered combustion alone for the sources covered by this FIP. Further, the EPA is seeking comment on whether additional control technology could be installed on these sources at or below the marginal cost threshold to achieve a lower emissions rate.

Compliance Assurance Requirement

The EPA is proposing to require stationary SI engines subject to this proposed FIP to conduct semi-annual performance testing in accordance with 40 CFR 60.8 to ensure that the engine is meeting the NO_X emissions limit. The EPA is proposing that affected engines then monitor and record hours of operation and fuel consumption to calculate ongoing compliance with the applicable emissions limit. In addition, the EPA is proposing that affected engines would use continuous parametric monitoring systems (CPMS) to ensure that the NO_X emissions limit is being met at all times. For example, engines utilizing layered combustion controls would need to monitor and record temperature, air to fuel ratio, and other parameters as appropriate to ensure that combustion conditions are optimized to reduce NO_X emissions and assure compliance with the emissions limit. For engines using SCR or NSCR, the EPA is proposing that source monitor and record parameters such as inlet temperature to the catalyst and pressure drop across the catalyst.

The EPA is seeking comment on whether it is feasible or appropriate to require affected engines to be equipped with continuous emissions monitoring systems (CEMS) to measure and monitor the NO_x emissions instead of conducting performance tests on a semiannual basis.

2. Cement and Concrete Product Manufacturing

Applicability

The EPA is proposing to establish regulatory requirements for the Cement and Concrete Product Manufacturing source category that apply to emissions units (kilns) that directly emit or have the potential to emit 100 tpy or more of NO_X. Further, the EPA is proposing emissions limits based on type of unit to ensure that the necessary NO_X emissions reductions occur. The EPA is seeking comment on whether it should set an applicability threshold based on a unit's design production capacity rather than an emissions threshold.

Emissions Limitations and Rationale

In developing the emissions limits for the Cement and Concrete Manufacturing industry, the EPA reviewed RACT NO_X rules, air permits, and consent decrees. These rules and source-specific requirements most commonly express the emissions limits for this industry in terms of mass of pollutant emitted (pounds) per kiln's clinker output (tons), *i.e.,* pounds of NO_X emitted per ton of clinker produced. A regulated entity routinely monitors and keeps track of its clinker output as it pertains to a kiln design capacity and the plant's production. Therefore, the EPA believes that this form of NO_X emissions limit is effective, practicable and convenient to record and report to an air agency.

In determining the averaging time for the limit, the EPA considered the NSPS for Portland Cement Plants at 40 CFR part 60, subpart F. Section 60.62(a)(3) of this subpart establishes a 30-operating day rolling average period for the NO_X emitted per ton of clinker produced and further states that an operating day includes all valid data obtained in any daily 24-hour period during which the kiln operates and excludes any measurements made during the daily 24-hour period when the kiln was not operating. In addition, 40 CFR 60.44b(i) requires that compliance with the applicable NO_X emissions limit be determined on a 30-day rolling average basis. The EPA is proposing to require a 30-operating day rolling average period as the averaging time frame for this particular industry. The proposed averaging timeframe is consistent with the longstanding national technology-based NSPS for this industry at 40 CFR part 60, subpart F. Furthermore, an air agency may choose to require an averaging period shorter than a 30-operating day rolling average in air permit(s) issued to these plants. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production.

Based on the available information for this industry, applicable State and local air agency rules, and active air permits or enforceable orders issued to affected cement plants, the EPA is proposing the following emissions limits for cement kilns:

[314] Ozone Transport Commission, *Technical Information Oil and Gas Sector Significant Stationary Sources of NO_X Emissions* at 24–25.

TABLE VII.C–2—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR KILN TYPES IN CEMENT AND CONCRETE PRODUCT MANUFACTURING

Kiln type	Proposed NO_X emissions limit (lb/ton of clinker)	Additional information
Long Wet	4.0	Limits reviewed ranged between 3.88–5.2; one State rule allows as high as 6.0; with addition of a post combustion NO_X control the upper range could be reduced significantly.
Long Dry	3.0	Limits reviewed showed 5.1; with addition of post combustion NO_X control the limit could be reduced significantly; limit of 3.0 would achieve a 41% reduction in NO_X emissions.
Preheater	3.8	Limits reviewed ranged between 1.5–3.44; limit of 3.8 is consistent with 30 TAC 117.3110(a)(3) and 35 IAC 217.224(a).
Precalciner	2.3	Requires post combustion NO_X control; consistent with permit A0017 for Lehigh Southwest Cement Company issued on May 5, 2020 by the Bay Area Air Quality Management District.
Preheater/Precalciner	2.8	Limits reviewed ranged between 1.8–3.4; limit of 2.8 is consistent with 30 TAC 117.3110(a)(4); Mitsubishi Cement Corporation Lucerne Valley Federal Operating Permit 11800001 issued by the Mojave Desert Air Quality Management District (MDAQMD) June 18, 2020; MDAQMD Rule 1161 (C)(2); and Illinois 35 IAC 217.224(a).

Although the EPA is proposing NO_X emissions limits based on the specific kiln types listed in Table VII.C–2, to provide operational flexibility the EPA is also proposing a source cap limit expressed in tons per day (tpd) of NO_X for each individual cement plant according to the following equation.

$$CAP2015\ Ozone\ Transport = \frac{(KW\ x\ NW) + (KD\ x\ ND)}{(2000\frac{pounds}{ton}\ x\ 365\frac{days}{year})}$$

Where:

CAP2015 Ozone Transport = total allowable NO_X emissions from all cement kilns located at one cement plant, in tons per day, on a 30-operating day rolling average basis;

KD = 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns;

KW = 3.4 pounds NO_X per ton of clinker for long wet kilns;

ND = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all dry preheater-precalciner or precalciner kilns located at one cement plant; and

NW = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all long wet kilns located at one cement plant.

An affected cement plant will need to comply with both the source cap limit and the specific NO_X emissions limits assigned to its individual kiln type(s). The EPA notes that the above source cap would be calculated and assigned to operating kilns in a particular plant. That is, the total allowable NO_X emissions in tpd from one plant cannot be traded with another plant, regardless of these plants' control of ownership or operator's status, or regardless of these plants' proximity to each other or their location.

The EPA is soliciting comment on whether it is feasible or appropriate to phase out and retire existing long wet kilns in the affected states and to replace them with more energy efficient and less emitting units like preheater/precalciner installations. The EPA is also requesting comment on the time needed to complete such a task. It has been shown that such kilns replacements (preheater/precalciner kilns), when equipped with post-combustion NO_X control devices such as SNCR, are capable of meeting NO_X emissions limit of 1.5 lb/ton of clinker on a 30-operating day basis. For this reason, the EPA proposes to find that conversion from long wet kilns to preheater/precalciner installations is generally feasible. Given that long wet kilns are less energy efficient and generally emit more NO_X than other kiln types, conversion to preheater/precalciner installations would be the most effective method of NO_X reduction (per ton of clinker produced).

Additionally, EPA is soliciting comments on whether it is feasible or appropriate to require sources with existing preheater/precalciner kilns in the affected states that currently utilize low NO_X burners, combustion controls, staged combustion, or mid-kiln firing to add and operate a post combustion control device like SNCR or SCR to further improve their NO_X removal efficiency and lower NO_X emissions to 1.95 lb/ton of clinker or less. The EPA is also requesting comments on the time needed to complete such an addition.

We note that the EPA previously stated that it expects that the controls for cement kilns would take at least 2 years to install on a sector-wide basis across the 12-state region affected by the Revised CSAPR Update.[315]

Compliance Assurance Requirements

The EPA is proposing that performance tests be conducted on a semiannual basis. Such tests shall be conducted in conformance with the requirements of 40 CFR 60.8. Stack tests will need to conform with the Test Methods and Procedures in 40 CFR 60 appendix A, or other EPA-approved (federally enforceable) test methods and procedures.

The EPA is soliciting comments on whether it is feasible or appropriate to require affected units (kilns) to be equipped with CEMS to measure and monitor the NO_X concentration (emissions level) instead of conducting performance tests on semiannual basis.

We are also soliciting comment on whether it is appropriate for the affected units (kilns) to use CPMS instead of CEMS to monitor the NO_X concentration (emissions level). We note that CPMS, also called parametric monitoring, measures a parameter (or multiple parameters) as a key indicator of system performance. The parameter is generally an operational parameter of the process

[315] 85 FR 68999 (October 30, 2020).

or the air pollution control device (APCD) that is known to affect the emissions levels from the process or the control efficiency of the APCD. Examples of parametric monitoring include kiln feed rate, clinker production rate, fuel type, fuel flow rate, specific heat consumption, secondary air temperature, kiln feed-end temperature, preheater exhaust gas temperature, induced draught fan pressure drop, kiln feed-end percentage oxygen, percentage downcomer oxygen, primary air flow rate, ammonia feed rate and slippage.

3. Iron and Steel Mills and Ferroalloy Manufacturing

Applicability

The EPA is proposing to establish regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to emissions units that directly emit or have the potential to emit 100 tpy or more of NO_X and to facilities containing two or more such units that collectively emit or have the potential to emit 100 tpy or more of NO_X. The EPA is setting emissions limits based on type of unit to ensure that the necessary emissions reductions occur across all units of the same type. The EPA is seeking comment on whether it should set an applicability threshold based on a unit's production capacity rather than an emissions threshold.

Emissions Limitations and Rationale

In developing the emissions limits for the Iron and Steel and Ferroalloy Manufacturing industry, the EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees. These rules and source-specific requirements most commonly express the emissions limits for this industry in terms of mass of pollutant emitted (pounds) per operating hour (hours) (*i.e.,* pounds of NO_X emitted per production hour), pounds per energy unit (*i.e.,* million British thermal unit (mmBtu)), or pounds of NO_X per ton of steel produced. A regulated entity routinely monitors and keeps track of its production in terms of tons of steel produced per hour (heat rate) as it pertains to the facility's rate of iron and steel production. Depending on the type of unit and industry practice, the EPA is proposing rate-based emissions limits in the form of lb/mmBtu, production-based limits in the form of lb/ton, and work practice standards.

In determining the averaging times for the limits, EPA initially reviewed the NESHAP for Iron and Steel Foundries codified at 40 CFR part 63 subpart EEEEE, the NESHAP for Integrated Iron and Steel manufacturing facilities codified at 40 CFR part 63 subpart FFFFF, the NESHAP for Ferroalloys Production: Ferromanganese and Silicomanganese codified at 40 CFR part 63 subpart XXX, and the NESHAP for Ferroalloys Production Facilities codified at 40 CFR part 63 subpart YYYYYY. EPA also reviewed various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations. Based on this information, the EPA is proposing to require a 30-operating day rolling average period as the averaging time frame for this particular industry. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production.

Based on the available information for this industry, applicable federal and state rules, and active air permits or enforceable orders issued to affected facilities in the iron and steel and ferroalloy manufacturing industry, the EPA proposes the following emissions limits:

TABLE VII.C–3—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS

Emissions unit	Proposed NO_X emissions standard or requirement (lbs/hour or lb/mmBtu)	Additional information
Blast Furnace	0.03 lb/mmBtu	OH NO_X RACT rules limit NO_X emissions from blast furnaces to 0.06 lb/mmBtu without requiring specific control technology. Control NO_X at stoves (typically 3 or 4 per blast furnace), assuming 40–50% reduction) by burner replacement plus SCR.
Basic Oxygen Furnace	0.07 lb/ton	Potential 25–50% reduction by SCR/SNCR from 0.14 lb/ton based on emissions testing.
Electric Arc Furnace	0.15 lb/ton steel	Example permit limits at around 0.2 lb/ton. Assumes 25% reduction by SCR to achieve 0.15 lb/ton steel.
Ladle/tundish Preheaters	0.06 lb/mmBtu	Nucor Kankakee BACT permit limit issued January 2021 is 0.1 lb/mmBtu, 2021. Assume 40% reduction by SCR.
Reheat furnace	0.05 lb/mmBtu	Sterling Steel permit, issued 2019: Low-NO_X natural gas fired burners designed to emit no more than 0.073 lb NO_X/mmBtu, Ohio RACT limit is 0.09 lb/mmBtu. Assume 40% reduction by SCR.
Annealing Furnace	0.06 lb/mmBtu	Big River Steel (AR) 2018 limit and Benteler Steel (LA) 2019 limit (0.11 lb/mmBtu), 85 mmBtu/hr and 13 mmBtu/hr, respectively. Lowest was 0.0915 lb/mmBtu, Nucor AR. Assume 40% reduction by SCR.
Vacuum Degasser	0.03 lb/mmBtu	0.05 lb/mmBtu Nucor Darlington (SC) and Nucor Tuscaloosa (AL). Assume 40% reduction by SCR.
Ladle Metallurgy Furnace	0.1 lb/ton	Assume 40% reduction by SCR.
Taconite Production Kilns	Work practice standard to install and operate low NO_X burners.	Consistent with requirements in Minnesota Taconite FIP *See 81 FR 21671.*
Coke Ovens (charging)	0.15 lb/ton of coal charged	Assume 50% reduction staged combustion and/or limited use SCR/SNCR during charging operations from AP–42 0.3 lb/ton emission factor.
Coke Ovens (pushing)	0.015 lb/ton of coal pushed	SunCoke Middletown limit is 0.02 lb/ton of coal. Assume 25% reduction by SCR.
Boilers—Coal	0.20 lb/mmBtu	See explanation in Section VII.C.5.
Boilers—Residual oil	0.20 lb/mmBtu	See explanation in Section VII.C.5.
Boilers—Distillate oil	0.12 lb/mmBtu	See explanation in Section VII.C.5.

TABLE VII.C–3—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR IRON AND STEEL AND FERROALLOY EMISSIONS UNITS—Continued

Emissions unit	Proposed NO_X emissions standard or requirement (lbs/hour or lb/mmBtu)	Additional information
Boilers—Natural gas	0.08 lb/mmBtu	See explanation in Section VII.C.5.

Due to the many types of units within Iron and Steel Mills and Ferroalloy Manufacturing facilities that are not currently subject to NO_X limitations of the stringency necessary to eliminate significant contribution, most of the emissions limits in this proposed rule are based on examples of permitted emissions and estimated reduction potential from the identified control technology. Based on the selection of SCR, SNCR, and burner replacement in the non-EGU screening assessment, the EPA assumed reductions of 20 to 50 percent from current permitted limits and emissions tests depending on the type of unit and controls being implemented.

In addition, for Taconite Production Kilns, the EPA does not currently have the data to determine appropriate emissions limits that these units could achieve by installing low NO_X burners. Therefore, the EPA is proposing to require the installation of low NO_X burners for Taconite Production Kilns and work practice standards for operating these control technologies to achieve emissions reductions. The EPA is also proposing to require these sources to perform performance tests and establish a unit-specific emissions limit at that time. These work practice standards are consistent with EPA's Taconite FIP for Minnesota. *See* 81 FR 21671 (April 12, 2016). Due to the ongoing nature of this FIP, the EPA is proposing to require installation of specific control technologies and a period of evaluation before setting a numerical emissions limit.

Compliance Assurance Requirements

The EPA is proposing to require each owner or operator of an affected facility that is subject to the NO_X emissions limit for Iron and Steel Mills and Ferroalloy Manufacturing emissions units contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. The EPA is proposing that each emissions unit will be required to conduct an initial performance test and to operate CEMS to assure compliance. In conducting the performance tests to demonstrate compliance, sources must use test methods and procedures in 40 CFR 60 appendix A, Method 7E, or other EPA-approved (federally enforceable) test methods and procedures. The EPA is also soliciting comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits.

4. Glass and Glass Product Manufacturing

Applicability

The EPA is proposing to establish regulatory requirements for the Glass and Glass Product Manufacturing source category that apply to emissions units that directly emit or have the potential to emit 100 tpy or more of NO_X. The EPA is setting emissions limits based on type of unit to ensure that the necessary emissions reductions occur. The EPA is seeking comment on whether it should set an applicability threshold based on a unit's production capacity rather than an emissions threshold.

Emissions Limitations and Rationale

In developing the emissions limits for the Glass and Glass Product Manufacturing industry, the EPA reviewed RACT NO_X rules, air permits, Alternative Control Techniques (ACT), and consent decrees. These rules and source-specific requirements most commonly express the emissions limits for this industry in terms of mass of pollutant emitted (pounds) per weight of glass removed from the furnace (tons), *i.e.,* pounds of NO_X emitted per ton of glass produced. A regulated entity routinely monitors and keeps track of its glass outputs as it pertains to a furnace's design capacity and the plant's production. Therefore, the EPA believes that this form of NO_X emissions limit is effective, practicable, and convenient to record and report to an air agency.

In determining the averaging time for the limits, the EPA initially reviewed the NSPS for glass manufacturing plants codified at 40 CFR part 60 subpart CC. This NSPS applied to any glass melting furnace in an affected facility that commenced construction or modification after June 15, 1979, and produced more than 5 tons of glass per day. It was noted that the NSPS only provides standards for particulate matter and does not provide standards or averaging times for NO_X. In order to determine the averaging time for the NO_X emissions limits, the EPA reviewed various RACT NO_X rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations.

Most of the states within the OTR implement RACT regulations for the glass manufacturing industry that do not specify presumptive NO_X limits.[316] With respect to those RACT rules in the OTR states that contain presumptive RACT NO_X limits for glass manufacturing furnaces, EPA found variations in averaging times, ranging from a 30-day rolling average to a more stringent daily average.[317] The EPA also reviewed RACT NO_X regulations for the glass manufacturing industry outside the OTR and observed that 30-day rolling averages and daily averages varied throughout the states.[318] The EPA is proposing to require owners or operators of glass manufacturing furnaces to comply with the applicable presumptive NO_X emissions limits on a 30-day rolling average time frame. This averaging time frame is consistent with other statewide RACT NO_X regulations for this particular industry. Furthermore, a state's air agency may choose to require an averaging period shorter than a 30-operating day rolling

[316] RACT NO_X rules of the following OTR states CT, DC, DE, MD, ME, NH, NY, RI, VA, and VT do not provide presumptive NO_X limits for glass manufacturing sources. These RACT regulations require owners or operators to submit RACT case-by-case analysis.

[317] Pennsylvania's presumptive RACT NO_X emissions limits are based on 30-day rolling average. New Jersey's and Massachusetts' rules contain more stringent daily averages. Maryland's RACT rule, section 26.11.09.08.I, requires owner or operators to optimize combustion by performing daily oxygen tests and maintain excess oxygen at 4.5% or less. See *http://www.dsd.state.md.us/comar/comarhtml/26/26.11.09.08.htm.*

[318] For example, presumptive RACT NO_X emissions limits in California are based on both 30-day rolling and daily averages (*see https://www.valleyair.org/rules/currntrules/R4354%20051911.pdf*). Wisconsin's NO_X emissions limits are based on a 30-day rolling average (*see https://casetext.com/regulation/wisconsin-administrative-code/agency-department-of-natural-resources/environmental-protection-air-pollution-control/chapter-nr-428-control-of-nitrogen-compound-emissions/subchapter-iv-NOX-reasonably-available-control-technology-requirements/section-nr-42822-emission-limitation-requirements*).

average in air permits or RACT regulations for these plants. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operation and production.

Based on the available information for this industry, applicable state and local air agency rules, and active air permits or enforceable orders issued to affected glass manufacturing plants, EPA is proposing the following emissions limits for glass manufacturing furnaces:

TABLE VII.C–4—SUMMARY OF PROPOSED NO_X EMISSIONS LIMITS FOR FURNACE UNIT TYPES IN GLASS AND GLASS PRODUCT MANUFACTURING

Furnace type	Proposed NO_X emissions limit (lb/ton of glass produced)	Additional information
Container Glass Manufacturing Furnace.	4.0	Limits reviewed ranged between 1–4; one state rule allowed as high as 5; with addition of post combustion NO_X controls, the upper range could be reduced significantly; consistent with 25 Pennsylvania Code 129.304(a)(1) and New Jersey Administrative Code 7:27 Subchapter 19.1.
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace.	4.0	Limits reviewed ranged between 1.36–4; one state rule allowed as high as 7; with addition of post combustion control the limit could be reduced significantly; limit of 4.0 is consistent with RACT regulations for states located within OTR.
Flat Glass Manufacturing Furnace.	9.2	Limits reviewed ranged between 5–9.2; with the addition of post combustion controls the limit could be reduced significantly; consistent with San Joaquin Valley Air Pollution Control District Rule 4354 5.1.1 and New Jersey Administrative Code 7:27 Subchapter 19.1.

The EPA is soliciting comment on whether it is feasible or appropriate to phase out and retire existing glass manufacturing furnaces in the affected states and replace them with more energy efficient and less emitting units like all-electric melter installations. The EPA is also requesting comment on the time needed to complete such a task. All-electric melters are glass melting furnaces in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass.[319] All-electric melter furnaces could provide an energy efficient and NO_X emission-free alternative to current methods of melting and producing glass.

According to the EPA's ''Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing,'' [320] glass manufacturing furnaces may utilize combustion modifications equivalent to low-NO_X burners and oxy-firing. The EPA is soliciting comment on whether it is feasible or appropriate to require sources with existing glass manufacturing furnaces in affected states that currently utilize these combustion modifications to add and operate a post-combustion control device like SNCR and SCR to further improve their NO_X removal efficiency. The EPA is also requesting comments on the time needed to install such controls.

Compliance Assurance Requirements

The EPA is proposing to require each owner or operator of an affected facility that is subject to the NO_X emissions standards for glass manufacturing furnaces contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NO_X emissions discharged into the atmosphere from the affected facility. The EPA is also soliciting comments on alternative monitoring systems or methods that are equivalent to CEMS to demonstrate compliance with the emissions limits. In conducting the performance tests to demonstrate compliance, sources must use test methods and procedures in 40 CFR part 60 appendix A, method 7E, or other EPA-approved (federally enforceable) methods and procedures. Owners or operators must calculate and record the 30-operating day rolling emissions rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. Owners or operators of glass manufacturing furnaces installed with continuous emissions monitoring may demonstrate compliance with the emissions limit as follows: (1) Determine the average pounds of NO_X emitted per day, (2) determine the tons of glass removed per day during the same day, (3) divide the average pounds of NO_X emitted per day by the tons of glass removed per day as determined in step (2), and (4) compare the quotient to the emissions limits prescribed in the Section VII of this proposed rule. If the pollutant mass emissions rate is in lb/hr, the following equation [321] shall be used to convert the emissions rate to lb pollutant/ton of glass pulled:

$$lb\ emitted / ton\ of\ glass\ pulled = \frac{\frac{lb}{hr} emitted}{Pull\ rate\ in \frac{tons}{hr}}$$

[319] *See* definitions in 40 CFR part 60 subpart CC.

[320] ''Alternative Control Techniques Document—NO_X Emissions from Glass Manufacturing,'' EPA–453/R–94–037, June 1994.

[321] This equation is provided in the San Joaquin Valley Unified Air Pollution Control District's Rule 4354, section 8.1.

5. Boilers From Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills

Applicability

The EPA is proposing to establish regulatory requirements for the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills industries that apply to boilers within these facilities that have a design capacity of 100 mmBtu/hr or greater. These requirements are consistent with EPA's findings at Step 3 with respect to Tier 2 non-EGU industries. As noted below, we do not believe boilers meeting this size classification exist within the other Tier 2, or Tier 1 industries, but if they do, the EPA proposes that they would also be subject to the requirements of this part. Based on our review of the potential emissions from industrial boilers of various fuel types, we find that use of a boiler design capacity of 100 mmBtu/hr reasonably approximates the selection of 100 tpy used within the Non-EGU Screening Assessment memorandum. Therefore, boilers subject to the requirements of this section of the proposed rule are those found within any of the 23 covered states with non-EGU emissions reduction obligations that are within a Tier 1 or Tier 2 industry and have a design capacity of 100 mmBTU/hr or greater. The EPA is seeking comment on whether EPA should alternatively set an applicability threshold based on potential to emit.

Emissions Limitations and Rationale

This section of the proposed rule applies to certain boilers located at any facility identified as a Tier 2 industry within the non-EGU screening assessment. As described within the Non-EGU Screening Assessment memorandum, the EPA reviewed the projected 2026 emissions data to identify large boilers within the Tier 2 industries, defined as boilers projected to emit more than 100 tons per year in 2026. Boilers meeting this threshold were found in three of the five Tier 2 industries, as identified in Table VII.C.5–1.

TABLE VII.C.5–1—TIER 2 INDUSTRIES WITH LARGE BOILERS AND ASSOCIATED NAICS CODES

Industry	NAICS code
Basic Chemical Manufacturing	3251xx
Petroleum and Coal Products Manufacturing	3241xx
Pulp, Paper, and Paperboard Mills	3221xx

The EPA did not find large boilers within the Lime and Gypsum Product Manufacturing (NAICS code 3274xx) or the Metal Ore Mining industries (NAICS code 2122xx). As such the EPA is not expressly proposing to include boilers in those industries. However, if as a result of receiving additional information during the comment period the EPA identifies large boilers within these two industries that meet the applicability criteria described below, those boilers could be subject to the requirements of the final rule.

As described within the Non-EGU Sectors TSD, the RACT rules we reviewed containing NO_X limits for industrial boilers relied primarily on design capacity in mmBtu/hr as the metric for selecting design criteria. The EPA is proposing to use that same metric to establish control requirements for boilers with a design capacity of 100 mmBtu/hr or greater. As noted within the Non-EGU Sectors TSD, boilers rated at 100 mmBtu/hr or greater can emit large amounts of NO_X, particularly if they do not operate NO_X control equipment.

The EPA reviewed NO_X emissions limits for industrial boilers with design capacities of 100 mmBtu/hr or greater that have been adopted by states and incorporated into their SIPs. The Non-EGU Sectors TSD contains a detailed discussion of that evaluation. Based on our review, we propose to establish the following NO_X emissions limits for coal, oil, and gas fired industrial boilers located at a Tier 2 industry:

TABLE VII.C.5–2—PROPOSED NO_X EMISSIONS LIMITS FOR INDUSTRIAL BOILERS >100 MMBTU/HR

Unit type	Emissions limit (lbs NO_X/mmBtu)	Additional information
Coal	0.20	Limits reviewed ranged from 0.08 to 1.0. Proposed limit will likely require a combination of combustion controls or post-combustion controls.
Residual oil	0.20	Limits reviewed ranged from 0.15 to 0.50. Proposed limit will likely require combustion controls.
Distillate oil	0.12	Limits reviewed ranged from 0.10 to 0.43. Proposed limit will likely require combustion controls.
Natural gas	0.08	Limits reviewed ranged from 0.06 to 0.25. Proposed limit will likely require a combination of combustion controls or post-combustion controls.

Additional information on the EPA's derivation of these proposed emissions rates for boilers is provided below and in the Non-EGU Sectors TSD.

The EPA notes that some coal, oil, and gas-fired industrial boilers may have already installed combustion or post-combustion control equipment, such as SCR or SNCR, sufficient to meet the emission limits established in this FIP. Some of the boilers covered by this FIP might have install controls to meet the emission limits contained within EPA's NSPS located at 40 CFR 60 Subpart Db, which requires that some fossil fuel-fired units that commenced construction, modification, or reconstruction after June 19, 1984, meet various NO_x emission limits based on factors such as unit type or heat rate. Additionally, industrial boilers located in ozone nonattainment areas or within the ozone transport region may have installed controls to meet emission limits adopted by states to meet NO_x RACT requirements.

a. Coal-Fired Industrial Boilers

Coal-fired industrial boilers subject to the proposed requirements of this section would have to meet a NO_X emissions limit of 0.2 lbs/mmBtu on a 30-day rolling average basis.

Various forms of combustion and post-combustion NO_X control technology exist that should enable most facilities to be retrofit with equipment that will enable them to meet these emissions limits. Additionally, as noted in the Non-EGU Sectors TSD, many states containing ozone nonattainment areas or located within the OTR have already adopted emissions limits similar to or more stringent than the limits the EPA proposes here. Furthermore, some coal-fired industrial boilers may have installed combustion or post-combustion control equipment to meet the emissions limits contained within EPA's NSPS located at 40 CFR part 60 subpart Db, which requires that coal-fired industrial boilers meet a NO_X emissions limit of between 0.5 and 0.8

lbs/mmBtu depending on unit type.[322] Enhancements to or retrofit of additional NO_X control technology should enable most sources to meet the proposed NO_X limit.

There are two main types of NO_X control technology that we believe can be retrofit to most existing industrial boilers, or incorporated into the design of new boilers, to meet our proposed emissions limits. These two control types are combustion controls and post-combustion controls, and in some instances both types are used together. As noted in the EPA's ''Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers'' (hereafter ''ICI Boiler ACT''),[323] the type of NO_X control available for use on a particular unit depends primarily on the type of boiler, fuel type, and fuel-firing configuration. For example, Table 2–3 of the ICI Boiler ACT indicates which types of combustion and post-combustion NO_X controls are suitable to various types of coal-fired ICI boilers. We note that one type of combustion control, staged combustion air, and one type of post-combustion control, SNCR, are indicated as being compatible with all coal-fired unit types. Additional resources are available that document the availability of NO_X control equipment for industrial boilers.[324]

b. Oil-Fired Industrial Boilers

Most oil-fired boilers are fueled by either residual (heavy) oil or distillate (light) oil. The proposed NO_X emissions limit for residual oil-fired boilers subject to the requirements of this section is 0.2 lbs/mmBtu, and the proposed emissions limit for distillate oil-fired boilers is 0.12 lbs/mmBtu. The proposed averaging time for these emissions limits is a 30-day rolling average. As with coal-fired industrial boilers, a number of combustion and post-combustion NO_X control technologies exist that should enable most facilities to meet these emissions limits, and the Non-EGU Sectors TSD identifies numerous states that have already adopted emissions limits similar to the limits EPA proposes here. Table 2–3 of the ICI Boiler ACT indicates that two types of NO_X combustion control, low-NO_X burners and flue gas recirculation, are commonly found on oil-fueled industrial boilers, and that SNCR, a post-combustion control technology, is suitable to most oil-fueled industrial boilers other than those of the packaged firetube design. Some oil-fired industrial boilers may have already installed combustion or post-combustion control equipment to meet the emissions limits contained within EPA's NSPS at 40 CFR part 60 subpart Db, which requires that distillate oil-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/mmBtu depending on heat release rate, and that residual oil-fired units meet a NO_X emissions limit of between 0.3 to 0.4 lbs/mmBtu also depending on heat release rate.[325] The additional resources noted in the paragraph above discussing coal-fired industrial boilers also contain useful information regarding effective NO_X control equipment for residual and distillate fueled industrial boilers.

c. Gas-Fired Industrial Boilers

The proposed NO_X emissions limit for gas-fired boilers subject to the requirements of this section is 0.08 lbs/mmBtu. The proposed averaging time for these emissions limits is a 30-day rolling average.

As with fossil-fuel-fired boilers, numerous combustion and post-combustion NO_X control technologies exist that should enable most facilities to meet these emissions limits, and many states have already adopted emissions limits similar to the limits the EPA proposes here. Table 2–3 of the ICI Boiler ACT indicates the same control technologies that are suitable for application to oil-fired boilers are also likely to be effective at controlling NO_X emissions from gas-fired industrial boilers. Some gas-fired industrial boilers may have already installed combustion or post-combustion control equipment to meet the emissions limits contained within EPA's NSPS at 40 CFR 60 Subpart Db, which requires that gas-fired units meet a NO_X emissions limit of between 0.1 to 0.2 lbs/MMBtu depending on heat release rate. The additional resources noted in the discussion of coal-fired industrial boilers also contain useful information regarding effective NO_X control equipment for gas-fired industrial boilers.

The EPA anticipates that the majority of boilers covered by this section of the FIP will combust one of the fuels for which we have proposed emissions limits. However, we request comment on whether emissions limits for other types of fuels should be included in a final FIP, and if so, the types of fuels and the emissions limits that boilers powered by these fuels should be required to meet. Additionally, the EPA seeks comment on whether the EPA should establish less stringent emissions rates for boilers with low utilization rates, and if so, the appropriate emissions rate(s) and corresponding boiler utilization rate(s). The EPA also seeks comment on whether a different averaging time other than the 30-day averaging time proposed for boilers would be more appropriate and requests information supporting any suggested alternative.

Compliance Assurance Requirements

Given the similarities in the types of units covered, the EPA proposes that boilers subject to the requirements of this section demonstrate compliance in a manner similar to the emissions monitoring requirements found in section 60.45 of the NSPS for industrial, commercial, and institutional (ICI) boilers at 40 CFR part 60 subpart D. Those requirements include, among other provisions, the performance of an initial compliance test, installation of a CEMS unless the initial performance test indicates the unit's emissions rate is 70 percent or less of the required emissions rate, and an annual stack test for units not required to install a CEMS.

D. Submitting a SIP

A state may submit a SIP at any time to address CAA requirements that are covered by a FIP, and if the EPA approves the SIP it would replace the FIP, in whole or in part, as appropriate.[326] The EPA has established certain specialized provisions for replacing FIPs with SIPs within all the CSAPR trading programs, including the use of so-called ''abbreviated SIPs'' and ''full SIPs,'' *see* 40 CFR 52.38(a)(4) and (5) and (b)(4), (5), (8), (9), (11), and (12); 40 CFR 52.39(e), (f), (h), and (i). For a state to remove all FIP provisions through an approved SIP revision, a state would need to address all of the required reductions addressed by the FIP for that state, *i.e.,* reductions achieved through both EGU control and non-EGU control, as applicable to that state. Additionally, tribes in Indian country within the geographic scope of this proposed rule may elect to work with EPA under the Tribal Authority Rule to replace the FIP for areas of Indian country, in whole or in part, with a tribal implementation plan or

[322] 40 CFR 60.44b.

[323] ''Alternative Control Techniques Document—NO_X Emissions from Industrial/Commercial/Institutional (ICI) Boilers,'' EPA–453/R–94–022, March 1994.

[324] For example, see ''Applicability and Feasibility of NO_X, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional Boilers,'' Northeast States for Coordinated Air Use Management, November 2008 (revised January 2009) and ''Nitrogen Oxides (NO_x), Why and How They Are Controlled,'' EPA, Clean Air Technical Center, 456/F–99–006R, November 1999.

[325] 40 CFR 60.44b.

[326] CAA sections 110(c)(1)(B), 110(k)(3).

reasonably severable portions of a tribal implementation plan.

Under the proposed new FIPs for the 25 states whose EGUs would be required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with its proposed modifications, ''abbreviated'' and ''full'' SIP options continue to be available. An ''abbreviated SIP'' allows a state to submit a SIP revision that would establish state-determined allowance allocation provisions replacing the default FIP allocation provisions but leaves the remaining FIP provisions in place. A ''full SIP'' allows a state to adopt a trading program meeting certain requirements that would allow sources in the state to continue to use the EPA-administered trading program through an approved SIP revision, rather than a FIP. In addition, as under past CSAPR rulemakings, the EPA proposes to provide states with an opportunity to adopt state-determined allowance allocations for existing units for the second control period under this rule—in this case, the 2024 control period—through streamlined SIP revisions. *See* 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

1. SIP Option To Modify Allocations for 2024 Under EGU Trading Program

As with the start of past CSAPR rulemakings, the EPA proposes to allow a state to use a similar process to submit a SIP revision establishing allowance allocations for existing EGU units in the state for the second control period of the new requirements, *i.e.,* in 2024, to replace the EPA-determined default allocations. This proposed process would use updated deadlines, *i.e.,* a state must submit a letter to EPA within 60 days of publication of the final rule indicating its intent to submit a complete SIP revision by September 1, 2023. The SIP would provide in an EPA-prescribed format a list of existing units within the state and their allocations for the 2024 control period. If a state does not submit a letter of intent to submit a SIP revision, the EPA-determined default allocations will be recorded by 90 days of publication of the final rule. If a state submits a timely letter of intent but fails to submit a SIP revision, the EPA-determined default allocations will be recorded by September 15, 2023. If a state submits a timely letter of intent followed by a timely SIP revision that is approved, the approved SIP allocations will be recorded by March 1, 2024.

The EPA requests comment on the proposed option to modify allowance allocations under the Group 3 trading program for EGUs for the 2024 control period through a SIP revision.

2. SIP Option To Modify Allocations for 2025 and Beyond Under EGU Trading Program

For the 2025 control period and later, the EPA proposes that states in the CSAPR NO_X Ozone Season Group 3 Trading Program can modify the EPA-determined default allocations with an approved SIP revision. For the 2025 control period and later, SIPs can be full or abbreviated SIPs. States will also have the option to expand applicability to include EGUs between 15 MWe and 25 MWe or, in the case of states subject to the NO_X SIP Call, as discussed in Section VII.F.1 of this proposed rule, large non-EGU boilers and combustion turbines. Inclusion of the large non-EGUs would serve as a mechanism to address the state's outstanding regulatory obligations under the NO_X SIP Call with respect to those sources, and the state would be allowed to allocate a defined quantity of additional Group 3 allowances because of the expanded set of sources. *See* above and 76 FR 48326–48332 for additional discussion of full and abbreviated SIP options; *see also* 40 CFR 52.38(b).

For states that want to modify the EPA-determined default allocations or expand applicability of the EGU trading program, the EPA proposes that a state could submit a SIP revision that makes changes only to one or both of those type of provisions while relying on the FIP for the remaining provisions of the EGU trading program. This abbreviated SIP option allows states to tailor the FIP to their individual choices while maintaining the FIP-based structure of the trading program. In order to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace EPA's default allocations with state-determined allocations, the EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

The proposed SIP submittal deadline for this type of revision is December 1, 2023, if the state intends for the SIP revision to be effective beginning with the 2025 control period. For states that submit this type of SIP revision, the EPA proposes that the deadline to submit state-determined allocations beginning with the 2025 control period under an approved SIP would be June 1, 2024, and the deadline for the EPA to record those allocations would be July 1, 2024. Similarly, under the proposed new deadlines a state could submit a SIP revision beginning with the 2026 control period and beyond by December 1, 2024, with state allocations for the 2026 control period due June 1, 2025, and the EPA recordation of the allocations by July 1, 2025.

The EPA requests comment on the proposed option to replace certain allowance allocation or applicability provisions under the Group 3 trading program for EGUs for control periods in 2025 and later years through a SIP revision.

3. SIP Option To Replace the Federal EGU Trading Program With an Integrated State EGU Trading Program

For the 2025 control period and later, the EPA proposes that states in the CSAPR NO_X Ozone Season Group 3 Trading Program can choose to replace the Federal EGU trading program with an integrated State EGU trading program through an approved SIP revision. Under this option, a state would submit a SIP revision that makes changes only to modify the EPA-determined default allocations or expand applicability of the EGU trading program and adopt identical provisions for the remaining portions of the EGU trading program. This SIP option allows states to replace these FIP provisions with state-based SIP provisions while continuing participation in the larger regional trading program. As with the abbreviated SIP option discussed above, in order to ensure the availability of allowance allocations for units in any Indian country within a state not covered by the state's CAA implementation planning authority, if the state chose to replace EPA's default allocations with state-determined allocations, EPA would continue to administer any portion of each state emissions budget reserved as a new unit set-aside or an Indian country existing unit set-aside.

Proposed deadlines for this type of SIP revision are the same as the deadlines for abbreviated SIP revisions. For the SIP-based program to start with the 2025 control period, the SIP deadline would be December 1, 2023, the deadline to submit state-determined allocations for the 2025 control period under an approved SIP would be June 1, 2024, and the deadline for the EPA to record those allocations would be July 1, 2024, and so on.

The EPA requests comment on the proposed option to replace the federal trading program for EGUs with an integrated state trading program for EGUs for control periods in 2025 and later years through a SIP revision.

4. SIP Revisions That Do Not Use the New Trading Program

States can submit SIP revisions to replace the FIP that achieve the necessary EGU emissions reductions but do not use the CSAPR NO_X Ozone Season Group 3 Trading Program. For a transport SIP revision that does not use the CSAPR NO_X Ozone Season Group 3 Trading Program, the EPA would evaluate the transport SIP based on the particular control strategies selected and whether the strategies as a whole provide adequate and enforceable provisions ensuring that the necessary emissions reductions (*i.e.,* reductions equal to or greater than what the Group 3 trading program will achieve) will be achieved. In order to address the applicable CAA requirements, the SIP revision should include the following general elements: (1) A comprehensive baseline 2023 statewide NO_X emissions inventory (which includes existing control requirements), which should be consistent with the 2023 emissions inventory that the EPA used to calculate the required state budget in this final proposed rule (unless the state can explain the discrepancy); (2) a list and description of control measures to satisfy the state emissions reduction obligation and a demonstration showing when each measure would be implemented to meet the 2023 and successive control periods; (3) fully-adopted state rules providing for such NO_X controls during the ozone season; (4) for EGUs greater than 25 MWe, monitoring and reporting under 40 CFR part 75, and for other units, monitoring and reporting procedures sufficient to demonstrate that sources are complying with the SIP (*see* 40 CFR part 51 subpart K (''source surveillance'' requirements)); and (5) a projected inventory demonstrating that state measures along with federal measures will achieve the necessary emissions reductions in time to meet the 2023 and successive compliance deadlines (*e.g.,* enforceable reductions commensurate with installation of SCR on coal-fired EGUs by the 2026 ozone season). The SIPs must meet procedural requirements under the Act, such as the requirements for public hearing, be adopted by the appropriate state board or authority, and establish by a practically enforceable regulation or permit(s) a schedule and date for each affected source or source category to achieve compliance. Once the state has made a SIP submission, the EPA will evaluate the submission(s) for completeness before acting on the SIP. EPA's criteria for determining completeness of a SIP submission are codified at 40 CFR part 51 appendix V.

For further information on replacing a FIP with a SIP, *see* the discussion in the final CSAPR rulemaking (76 FR 48326).

5. SIP Revision Requirements for Non-EGU Emissions Limits

EPA's promulgation of a non-EGU transport FIP would in no way affect the ability of states to submit, for review and approval, a SIP that replaces the requirements of the FIP with state requirements. In order to replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit an equivalent or greater amount of NO_X emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP.

After promulgation of the final FIP, the EPA anticipates that the most straightforward method for a state to submit a SIP revision to replace the non-EGU portion of the FIP for the state would be to provide a SIP that includes emissions limits at an equivalent or greater level of stringency than is specified for non-EGU sources meeting the applicability criteria and associated compliance assurance provisions for each of the unit types identified in Section VII.C of this proposed rule.

The EPA seeks comment on other potential methods by which states could develop a SIP to obtain emissions reductions from non-EGU sources that would replace the state's non-EGU portion of the FIP. The EPA recognizes that states may select emissions reductions strategies that differ from the emissions limitations included in the proposed non-EGU FIP. But the state must still demonstrate that the replacement SIP provides an equivalent or greater amount of emissions reductions as the proposed FIP. The EPA anticipates that such emissions reductions strategies would have to achieve reductions beyond those emissions reductions already projected to occur in EPA's emissions projections and air quality modeling conducted at Steps 1 and 2. Such reductions must also be achieved on the same timeframe as the reductions that would be required in a final FIP. A demonstration of equivalency using other control strategies is complicated by the fact that the proposed emissions limits for non-EGU sources are generally rate-based and expressed in a variety of forms; this will make comparative analysis to determine equivalency challenging.

In all cases, a SIP submitted by a state to replace the non-EGU FIPs would need to rely on permanent and practically enforceable controls measures that are included in the SIP and, once approved by the EPA, rendered federally enforceable. So-called ''demonstration-only'' or ''non-regulatory'' SIPs would be insufficient. Further, the EPA anticipates that states would bear the burden of establishing that the state's alternative approach achieves at least an equivalent level of emissions reduction as the FIP, and (unless merely adopting directly the control requirements of the FIP) the state would need to provide a Step 3 multifactor analysis that the state's SIP eliminates significant contribution.

E. Title V Permitting

This proposed rule, like CSAPR, the CSAPR Update, and the Revised CSAPR Update does not establish any permitting requirements independent of those under Title V of the CAA and the regulations implementing Title V, 40 CFR parts 70 and 71.[327] All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emissions limitations and other conditions as necessary to ensure compliance with the applicable requirements of the CAA, including the requirements of the applicable SIP. CAA sections 502(a) and 504(a), 42 U.S.C. 7661a(a) and 7661c(a). The ''applicable requirements'' that must be addressed in title V permits are defined in the title V regulations (40 CFR 70.2 and 71.2 (definition of ''applicable requirement'')).

The EPA anticipates that, given the nature of the units subject to this proposed rule, most if not all of the sources at which the units are located are already subject to title V permitting requirements. For sources subject to title V, the interstate transport requirements for the 2015 ozone NAAQS that are applicable to them under the new or amended FIPs would be ''applicable requirements'' under title V and therefore must be addressed in the title V permits. For example, requirements concerning designated representatives, monitoring, reporting, and recordkeeping, the requirement to hold allowances covering emissions, the compliance assurance provisions, and liability are ''applicable requirements'' that must be addressed in the permits.

Title V of the CAA establishes the basic requirements for state title V

[327] Part 70 addresses requirements for state title V programs, and Part 71 governs the federal title V program.

permitting programs, including, among other things, provisions governing permit applications, permit content, and permit revisions that address applicable requirements under final FIPs in a manner that provides the flexibility necessary to implement market-based programs such as the trading programs established in CSAPR, the CSAPR Update, the Revised CSAPR Update and this proposed rule. 42 U.S.C. 7661a(b); 40 CFR 70.6(a)(8) & (10); 40 CFR 71.6(a)(8) & (10).

In CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA established standard requirements governing how sources covered by that rule would comply with title V and its regulations.[328] 40 CFR 97.506(d), 97.806(d) and 97.1006(d). For any new or existing sources subject to this proposed rule, identical title V compliance provisions would apply, just as they would have in the CSAPR NO_X Ozone Season Group 3 Trading Program. For example, the title V regulations provide that a permit issued under title V must include ''[a] provision stating that no permit revision shall be required under any approved . . . emissions trading and other similar programs or processes for changes that are provided for in the permit.'' 40 CFR 70.6(a)(8) and 71.6(a)(8). Consistent with these provisions in the title V regulations, in CSAPR, the CSAPR Update and the Revised CSAPR Update, the EPA included a provision stating that no permit revision is necessary for the allocation, holding, deduction, or transfer of allowances. 40 CFR 97.506(d)(1), 97.806(d)(1) and 97.1006(d)(1). This provision is also included in each title V permit for an affected source. This proposed rule maintains the approach taken under CSAPR, the CSAPR Update and the Revised CSAPR Update that allows allowances to be traded (or allocated, held, or deducted) without a revision to the title V permit of any of the sources involved.

Similarly, this proposed rule would also continue to support the means by which a source in the proposed trading program can use the title V minor modification procedure to change its approach for monitoring and reporting emissions, in certain circumstances. Specifically, sources may use the minor modification procedure so long as the new monitoring and reporting approach is one of the prior-approved approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update (*i.e.,* approaches using a continuous emissions monitoring system under subparts B and H of part 75, an excepted monitoring system under appendices D and E to part 75, a low mass emissions excepted monitoring methodology under 40 CFR 75.19, or an alternative monitoring system under subpart E of part 75), and the permit already includes a description of the new monitoring and reporting approach to be used. *See* 40 CFR 97.506(d)(2), 97.806(d)(2) and 97.1006(d)(2); 40 CFR 70.7(e)(2)(i)(B) and 40 CFR 71.7(e)(1)(i)(B). As described in EPA's 2015 Title V Guidance, sources may comply with this requirement by including a table of all of the approved monitoring and reporting approaches under CSAPR, the CSAPR Update and the Revised CSAPR Update trading programs in which the source is required to participate, and the applicable requirements governing each of those approaches.[329] Inclusion of such a table in a source's title V permit therefore allows a covered unit that seeks to change or add to its chosen monitoring and recordkeeping approach to easily comply with the regulations governing the use of the title V minor modification procedure.

Under CSAPR, the CSAPR Update and the Revised CSAPR Update, in order to employ a monitoring or reporting approach different from the prior-approved approaches discussed previously, unit owners and operators must submit monitoring system certification applications to the EPA establishing the monitoring and reporting approach actually to be used by the unit, or, if the owners and operators choose to employ an alternative monitoring system, to submit petitions for that alternative to the EPA. These applications and petitions are subject to the EPA review and approval to ensure consistency in monitoring and reporting among all trading program participants. EPA's responses to any petitions for alternative monitoring systems or for alternatives to specific monitoring or reporting requirements are posted on EPA's website.[330] The EPA maintains the same approach in this proposed rule.

Consistent with EPA's approach under CSAPR, the CSAPR Update and the Revised CSAPR Update, the applicable requirements resulting from the new and amended FIPs generally will have to be incorporated into affected sources' existing title V permits either pursuant to the provisions for reopening for cause (40 CFR 70.7(f) and 71.7(f)) or the standard permit renewal provisions (40 CFR 70.7(c) and 71.7(c)).[331] For sources newly subject to title V that are affected sources under the FIPs, the initial title V permit issued pursuant to 40 CFR 70.7(a) should address the final FIP requirements.

As was the case in the CSAPR, the CSAPR Update and the Revised CSAPR Update, the new and amended FIPs impose no independent permitting requirements and the title V permitting process will impose no additional burden on sources already required to be permitted under title V.

F. Relationship to Other Emissions Trading and Ozone Transport Programs

1. NO_X SIP Call

States affected by both the NO_X SIP Call for the 1979 ozone NAAQS and any final ozone season requirements established upon finalization of this proposed rule for the 2015 ozone NAAQS will be required to comply with the requirements of both rules. EPA is proposing to require NO_X ozone season emissions reductions from EGUs larger than 25 MWe in many of the NO_X SIP Call states, and at greater stringency than required by the NO_X SIP Call, by requiring the EGUs to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program. Therefore, this proposed rule, if finalized, would satisfy the requirements of the NO_X SIP Call for these large EGUs.

In the Revised CSAPR Update, the EPA finalized the option for any NO_X SIP Call state that was also subject to the Revised CSAPR Update to voluntarily submit a SIP revision to expand the applicability of the Group 3 trading program to include all NO_X Budget Trading Program units, which in addition to large EGUs also include large non-EGU boilers and combustion turbines with a maximum design heat input greater than 250 mmBtu/hr. As part of such a SIP revision, the state

[328] The EPA has also issued a guidance document and template that includes instructions for how to incorporate the applicable requirements into a source's Title V permit. *See* Memorandum dated May 13, 2015, from Anna Marie Wood, Director, Air Quality Policy Division, and Reid P. Harvey, Director, Clean Air Market Division, EPA, to Regional Air Division Directors, Subject: ''Title V Permit Guidance and Template for the Cross-State Air Pollution Rule'' (''2015 Title V Guidance''), available at *https://www.epa.gov/sites/default/files/2016-10/documents/csapr_title_v_permit_guidance.pdf.*

[329] Id.

[330] *https://www.epa.gov/airmarkets/part-75-petition-responses.*

[331] A permit is reopened for cause if any new applicable requirements (such as those under a FIP) become applicable to an affected source with a remaining permit term of 3 or more years. If the remaining permit term is less than 3 years, such new applicable requirements will be added to the permit during permit renewal. *See* 40 CFR 70.7(f)(1)(I) and 71.7(f)(1)(I).

would be allowed to issue additional emissions allowances capped at a level intended to preserve the stringency of the Group 3 trading program. In today's proposed rule, the EPA is not proposing any changes to this provision of the Group 3 trading program.[332]

2. Acid Rain Program

This proposed rule, if finalized, would not affect any Acid Rain Program requirements. Any Title IV sources that are subject to provisions of this proposed rule would still need to continue to comply with all Acid Rain provisions. Acid Rain Program SO_2 and NO_X requirements are established independently in Title IV of the CAA and will continue to apply independently of this proposed rule's provisions. Acid Rain sources will still be required to comply with Title IV requirements, including the requirement to hold Title IV allowances to cover SO_2 emissions after the end of a compliance year.

3. Other Current Emissions Trading Programs

This proposed rule, if finalized, would not substantively affect any provisions of the CSAPR NO_X Annual, CSAPR SO_2 Group 1, CSAPR SO_2 Group 2, CSAPR NO_X Ozone Season Group 1, or CSAPR NO_X Ozone Season Group 2 trading programs for sources that continue to participate in those programs except with regard to the schedule for EPA to record certain allowance allocations, as discussed in Section VII.B.12 of this proposed rule. In addition, certain revisions are proposed to the CSAPR NO_X Ozone Season Group 2 Trading Program regulations to address the proposed transition of sources in eight states from that program to the CSAPR NO_X Ozone Season Group 3 Trading Program, as discussed in Section VII.B.11 of this proposed rule. Sources that are subject to any of the CSAPR trading programs will still be required to comply with all requirements, including the requirement to hold allowances to cover emissions after the end of a control period.

[332] In the CSAPR Update, the EPA finalized an identical option allowing NO_X SIP Call states to expand applicability of the Group 2 trading program to cover certain non-EGUs. If the geographic expansion of the Group 3 trading program proposed in this rulemaking is finalized as proposed, no NO_X SIP Call states would continue to be covered by the Group 2 trading program. Because the provision allowing NO_X SIP Call states to expand applicability of the Group 2 trading program to include such non-EGUs would therefore be obsolete, the EPA is proposing to remove the provision.

VIII. Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement

Consistent with EPA's commitment to integrating environmental justice in the agency's actions, and following the directives set forth in multiple Executive Orders, the Agency has analyzed the impacts of this proposed rule on communities with environmental justice concerns and engaged with stakeholders representing these communities to seek input and feedback. Executive Order 12898 is discussed in Section XI.J of this proposed rule and analytical results are available in Chapter 7 of the RIA.

A. Introduction

Executive Order 12898 directs EPA staff to identify the populations of concern who are most likely to experience unequal burdens from environmental harms; specifically, minority populations, low-income populations, and indigenous peoples.[333] Additionally, Executive Order 13985 is intended to advance racial equity and support underserved communities through federal government actions.[334] The EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA further defines the term fair treatment to mean that "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies." [335] In recognizing that minority and low-income populations often bear an unequal burden of environmental harms and risks, EPA continues to consider ways of protecting them from adverse public health and environmental effects of air pollution.

B. Analytical Considerations

EPA's environmental justice technical guidance [336] states that "[t]he analysis of potential EJ concerns for regulatory actions should address three questions:

1. Are there potential environmental justice concerns associated with environmental stressors affected by the regulatory action for population groups of concern in the baseline?
2. Are there potential environmental justice concerns associated with environmental stressors affected by the regulatory action for population groups of concern for the regulatory option(s) under consideration?
3. For the regulatory option(s) under consideration, are potential environmental justice concerns created or mitigated compared to the baseline?"

To address these questions in EPA's first quantitative EJ analysis in the context of a transport rule, the EPA developed a unique analytical approach that considers the purpose and specifics of the proposed rulemaking, as well as the nature of known and potential exposures and impacts. However, due to data limitations, it is possible that our analysis failed to identify disparities that may exist, such as potential environmental justice characteristics (*e.g.,* unemployed), environmental impacts (*e.g.,* other ozone metrics), and more granular spatial resolutions (*e.g.,* neighborhood scale) that were not evaluated.

For the proposed rule, we employ two types of analytics to respond to the above three questions: Proximity analyses and exposure analyses. Both types of analyses can inform whether there are potential EJ concerns for population groups of concern in the baseline (question 1).[337] In contrast, only the exposure analyses, which are based on future air quality modeling, can inform whether there will be potential EJ concerns after implementation of the regulatory options under consideration (question 2) and whether potential EJ concerns will be created or mitigated compared to the baseline (question 3). While the exposure analysis can respond to all three questions, it should be noted that exposure is limited to a single ozone metric, the maximum daily 8-hour average, averaged across the April through September warm season (AS–MO3). This ozone metric likely smooths potential daily ozone gradients and is not directly relatable to the National Ambient Air Quality Standard (NAAQS). Additionally, the ozone exposure analytic results are provided in two formats: Aggregated and distributional. The aggregated results provide an overview of potential ozone exposure differences across populations at the national- and state-levels, while the distributional results show detailed

[333] 59 FR 7629, February 16, 1994.

[334] 86 FR 7009, January 20, 2021.

[335] *https://www.epa.gov/environmentaljustice.*

[336] U.S. Environmental Protection Agency (EPA), 2015. Guidance on Considering Environmental Justice During the Development of Regulatory Actions.

[337] The baseline for proximity analyses is current population information (*e.g.,* 2021), whereas the baseline for ozone exposure analyses are the future years in which the regulatory options will be implemented (*e.g.,* 2023 and 2026).

information about ozone concentrations experienced by everyone within each population.

In Chapter 7 of the RIA we utilize the two types of analytics to address the three EJ questions by quantitatively evaluating (1) the proximity of affected facilities to potentially disadvantaged populations (Section 7.3.1), (2) the potential for disproportionate total ozone concentrations in the baseline across different demographic groups (Sections 7.4.1.1 and 7.4.2.1), and (3) how regulatory alternatives differentially impact the ozone concentration changes experienced by different demographic populations (Sections 7.4.1.2 and 7.4.2.2). Each of these analyses depends on mutually exclusive assumptions, was performed to answer separate questions, and is associated with unique limitations and uncertainties.

Baseline demographic proximity analyses can be relevant for identifying populations that may be exposed to local pollutants, such as NO_2 emitted from affected sources in this proposed rule. However, such analyses are less useful here as they do not account for the potential impacts of this proposed rule on long-range ozone concentration changes. The baseline demographic proximity analysis presented in the RIA finds larger percentages of Hispanic individuals, Black individuals, people below the poverty level, people with less educational attainment, and people linguistically isolated living within 5 km and 10 km of an affected EGU, compared to national averages. It also finds larger percentages of people below the poverty level and with less educational attainment living within 5 km and 10 km of an affected non-EGU. Separately, the tribal proximity analysis finds multiple tribes and unique tribal lands located within 50 miles of an affected facility. These results do not in themselves demonstrate disproportionate impacts of affected facilities in the baseline but could suggest that emission reductions from this proposed rule may be responsive to potential local air quality concerns of nearby communities.

Whereas the proximity analyses are limited to evaluating local pollutants under baseline scenarios (question 1), the ozone exposure analyses can provide insight into all three EJ questions with regard to AS–MO3 concentrations. Even though both the proximity and ozone exposure analyses can improve understanding of baseline EJ concerns (question 1), the two should not be directly compared. This is because the demographic proximity analysis does not include air quality information and is based on current, not future, population information.

Importantly, the baseline analysis of AS–MO3 ozone concentrations responds to question 1 from EPA's environmental justice technical guidance document more directly than the proximity analyses, as it evaluates a form of the environmental stressor targeted by the regulatory action. Baseline AS–MO3 analyses show that certain populations, such as American Indians, Hispanics, and Asians, may experience somewhat higher AS–MO3 concentrations compared to the national average. The less educated and children may also experience higher concentrations compared to the national average, but to a lesser extent. Conversely, Black populations may experience lower AS–MO3 concentrations than the national average. Therefore, also in response to question 1, there likely are potential environmental justice concerns associated with ozone exposures affected by the regulatory action for population groups of concern in the baseline. However, these baseline exposure results have not been fully explored and additional analyses are likely needed to understand potential implications.

The ozone exposure analysis evaluates the impacts of the proposed rule on future ozone concentrations after rule implementation. When comparing across the policy, more-, and less-stringent regulatory alternatives, AS–MO3 concentrations are reduced across all populations evaluated in both future years and across both EGUs and non-EGUs. In other words, we expect that populations experiencing disproportionate AS–MO3 exposures in the baseline will experience similar disproportionate AS–MO3 exposures under the proposed rulemaking, although to a lesser absolute extent as the action described in this proposed rule is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus alleviate some pre-existing health risks of ozone across all populations evaluated. Therefore, in response to question 2, we expect that there will be potential EJ concerns with regard to AS–MO3 concentrations after implementation of the regulatory options under consideration.

Question 3 asks whether potential EJ concerns will be created or mitigated as compared to the baseline. As the RIA estimates disproportionate AS–MO3 exposures in the baseline and similar reductions in all population evaluated, we do not predict that potential EJ concerns related to AS–MO3 concentrations will be created or mitigated as compared to the baseline (question 3).

The ozone exposure results should not be extrapolated to ozone metrics other than AS–MO3. Detailed environmental justice analytical results can be found in Chapter 7 of the RIA.

C. Outreach and Engagement

Prior to this proposed rule, EPA initiated a public outreach effort to gather input from stakeholder groups likely to be interested in this proposed rule. Specifically, the EPA hosted an environmental justice webinar on October 26, 2021, to share information about the proposed rule and solicit feedback about potential environmental justice considerations. The webinar was attended by over 180 individuals representing state governments, federally recognized tribes, environmental NGOs, higher education institutions, industry, and the EPA.[338] Participants were invited to comment during the webinar or provide written comments to a pre-regulatory docket. The webinar was recorded and distributed to attendees after the event. Some of the key issues raised by stakeholders during the webinar and in the pre-proposal comments are described below.

Daily emissions rate limits. Several commenters asserted that cap and trade programs with seasonal limits on overall NO_X emissions do not prevent facilities from running their controls inefficiently on high ozone days. These commenters recommended that facilities linked to downwind ozone problems comply with daily rate limits to ensure that emissions reductions occur on days when ozone is highest. The commenters noted that daily limits could particularly benefit environmental justice communities located near facilities and would also benefit those located downwind.

Regulation of other sources. Several commenters asserted that the EPA should consider regulation of sources other than EGUs and sources of NO_X in rulemakings pertaining to issues of ozone transport. For example, some commenters asserted that the EPA should regulate emissions from non-EGUs, mobile sources, and sources of VOCs.

Environmental justice analysis and methodology in rulemakings. Several commenters offered recommendations to improve environmental justice analysis and methodology in rulemakings that address air pollution.

[338] This does not constitute EPA's tribal consultation under E.O. 13175, which is described in Section XI.F of this proposed rule.

One commenter recommended that the EPA should broadly: (1) Identify communities of interest, based on the number of and proximity to polluting facilities; (2) integrate demographic factors to discern social, economic, and racial disparities in these areas; (3) consider the community's particular vulnerabilities and sensitivities to health harms and risks, and exposure to cumulative health harms and risks; and (4) reach out to the community members near such facilities themselves to gain tangible, lived experiences across their lifetimes. The commenter also suggested that the EPA should build off factors identified in existing environmental justice screening tools, including EPA EJSCREEN and California's CalEnviroScreen. One commenter noted that in developing environmental justice analyses, the EPA should consider and address the need for regulatory certainty, including the need for clear regulatory definitions of environmental justice areas and clear requirements for those areas.

Environmental justice stakeholder outreach in rulemakings. Some commenters asserted that the EPA could improve stakeholder outreach in the rulemaking process. For example, one commenter noted that during the development of a rule proposal, the EPA could more directly reach out to all potentially impacted environmental justice communities, be more prepared to answer questions about the rule proposal, and be more aware of holidays when establishing comment periods.

Additionally, some comments touched on issues that are also relevant to other EPA policies and programs. For example, some commenters asserted that the EPA should base air pollutant transport policy more on monitored data rather than modeling data to promptly address air pollution in areas where current monitoring data indicates an exceedance of the NAAQS. Other commenters recommended that the EPA consider strengthening cost thresholds for Reasonably Available Control Technology (RACT), a program that is applicable to certain existing sources in non-attainment areas.

In addition to the engagement conducted prior to this proposed rule, EPA is providing the public, including those communities disproportionately impacted by the burdens of pollution, opportunities to engage in the EPA's public comment period for this proposed rule, including by hosting a public hearing. This public hearing will occur according to the schedule identified in the Public Participation section of this proposed rule.

IX. Costs, Benefits, and Other Impacts of the Proposed Rule

In the Regulatory Impact Analysis for the proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards (RIA), EPA estimated the benefits, compliance costs, and emissions changes that may result from the proposed rule for the analysis period 2023 to 2042. The estimated benefits and compliance costs are presented in detail in the RIA accompanying this proposed rule. EPA notes that for EGUs the estimated benefits and compliance costs are directly associated with generation shifting to minimize costs; fully operating existing SCRs during ozone season; fully operating existing SNCRs during ozone season; installing state-of-the-art combustion controls; imposing backstop emission rate limits on certain units that lack SCR controls; and unit-level decisions to retrofit or retire. EPA also notes that for non-EGUs the estimated benefits and compliance costs are directly associated with installing controls to meet the NO_X emissions limits presented in Section I.B above.

For EGUs, EPA analyzed this proposed rule's emission budgets using uniform control stringency represented by $1,800 per ton of NO_X (2016$) in 2023 and $11,000 per ton of NO_X (2016$) in 2026. EPA also analyzed a more and a less stringent alternative. The more and less stringent alternatives differ from the proposed rule in that they set different NO_X ozone season emission budgets for the affected EGUs and different dates for compliance with backstop emission rate limits.

For non-EGUs, EPA analyzed this proposed rule using a marginal cost threshold of up to $7,500 per ton (2016$) for 2026 for the following emissions units and industries: Reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; kilns in Cement and Cement Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; furnaces in Glass and Glass Product Manufacturing; and high-emitting boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. The less stringent alternative assumes there are emissions limits for all emission units from the proposal except for high-emitting boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills. The more stringent alternative assumes emissions limits for all emission units from the proposed rule and all boilers, not just high-emitting boilers, in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

Table IX–1 provides the projected 2023 through 2027, 2030, 2035, and 2042 EGU emission reductions for the evaluated regulatory control alternatives. For additional information on emissions changes, *see* Table 4.6 and Table 4–7 in Chapter 4 of the RIA.

TABLE IX–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042

	Proposed rule	Less stringent alternative	More stringent alternative
2023:			
NO_X (ozone season)	6,000	6,000	7,000
NO_X (annual)	10,000	10,000	10,000
SO_2 (annual) *	....	1,000	2,000
CO_2 (annual, thousand metric)	....	....	....
$PM_{2.5}$ (annual)	....	....	....
2024:			
NO_X (ozone season)	26,000	14,000	29,000
NO_X (annual)	42,000	22,000	45,000
SO_2 (annual)	42,000	20,000	43,000
CO_2 (annual, thousand metric)	18,000	10,000	19,000
$PM_{2.5}$ (annual)	4,000	1,000	4,000
2025:			

TABLE IX–1—EGU OZONE SEASON NO_X EMISSIONS CHANGES AND ANNUAL EMISSIONS REDUCTIONS (TONS) FOR NO_X, SO_2, $PM_{2.5}$, AND CO_2 FOR THE REGULATORY CONTROL ALTERNATIVES FROM 2023–2042—Continued

	Proposed rule	Less stringent alternative	More stringent alternative
NO_X (ozone season)	46,000	22,000	51,000
NO_X (annual)	73,000	33,000	80,000
SO_2 (annual)	83,000	39,000	84,000
CO_2 (annual, thousand metric)	37,000	19,000	38,000
$PM_{2.5}$ (annual)	9,000	2,000	9,000
2026:			
NO_X (ozone season)	47,000	32,000	53,000
NO_X (annual)	81,000	55,000	87,000
SO_2 (annual)	106,000	76,000	108,000
CO_2 (annual, thousand metric)	40,000	26,000	42,000
$PM_{2.5}$ (annual)	9,000	5,000	9,000
2027:			
NO_X (ozone season)	49,000	42,000	54,000
NO_X (annual)	88,000	76,000	95,000
SO_2 (annual)	129,000	113,000	131,000
CO_2 (annual, thousand metric)	43,000	34,000	46,000
$PM_{2.5}$ (annual)	10,000	7,000	10,000
2030:			
NO_X (ozone season)	52,000	52,000	57,000
NO_X (annual)	96,000	98,000	100,000
SO_2 (annual)	104,000	100,000	103,000
CO_2 (annual, thousand metric)	50,000	45,000	50,000
$PM_{2.5}$ (annual)	9,000	9,000	9,000
2035:			
NO_X (ozone season)	49,000	50,000	52,000
NO_X (annual)	90,000	93,000	93,000
SO_2 (annual)	96,000	93,000	98,000
CO_2 (annual, thousand metric)	38,000	36,000	38,000
$PM_{2.5}$ (annual)	11,000	12,000	10,000
2042:			
NO_X (ozone season)	47,000	47,000	48,000
NO_X (annual)	70,000	75,000	71,000
SO_2 (annual)	54,000	50,000	54,000
CO_2 (annual, thousand metric)	25,000	23,000	24,000
$PM_{2.5}$ (annual)	8,000	9,000	8,000

*SO_2 emissions reductions under the proposed rule are 350 tons and rounded to zero. SO_2 emissions reductions under the less stringent alternative are 507 tons and rounded to 1,000 tons. SO_2 emissions reductions are 1,699 tons under the more stringent alternative and rounded to 2,000 tons. Given the rounding, the difference between the reductions under the proposed rule and the less stringent alternative is approximately 160 tons.

Table IX–2 below provides a summary of the ozone season emissions for non-EGUs for the 23 states subject to the proposed non-EGU emissions limits starting in 2026, along with the estimated ozone season reductions for 2026 for the proposed rule and the less and more stringent alternatives. The analysis in the RIA assumes that the estimated reductions in 2026 will be the same in later years.

TABLE IX–2—OZONE SEASON (OS) NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE PROPOSED RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES *

State	2019 OS NO_X emissions [a]	Proposed rule—OS NO_X reductions	Less stringent alternative—OS NO_X reductions	More stringent alternative—OS NO_X reductions
AR	8,265	1,654	922	1,654
CA	14,579	1,666	1,598	1,777
IL	16,870	2,452	2,452	2,553
IN	19,604	3,175	2,787	3,175
KY	11,934	2,291	2,291	2,291
LA	35,831	6,769	4,121	6,955
MD	2,365	45	45	45
MI	18,996	2,731	2,731	3,093
MN	17,591	673	673	789
MO	9,109	3,103	3,103	3,103
MS	12,284	1,761	1,577	1,761
NJ	2,025	0	0	29
NV	2,418	0	0	0
NY	6,003	500	389	613
OH	19,729	2,790	2,611	2,814
OK	22,146	3,575	3,575	3,871

TABLE IX–2—OZONE SEASON (OS) NO_X EMISSIONS AND EMISSIONS REDUCTIONS (TONS) FOR NON-EGUS FOR THE PROPOSED RULE AND THE LESS AND MORE STRINGENT ALTERNATIVES *—Continued

State	2019 OS NO_X emissions [a]	Proposed rule—OS NO_X reductions	Less stringent alternative—OS NO_X reductions	More stringent alternative—OS NO_X reductions
PA	15,861	3,284	3,132	3,340
TX	47,135	4,440	4,440	6,596
UT	6,276	757	757	757
VA	7,041	1,563	1,465	1,660
WI	6,571	2,150	677	2,234
WV	9,825	982	982	982
WY	10,335	826	826	826
Totals	322,793	47,186	41,153	50,918

* In the non-EGU screening assessment for 2026, EPA estimated emissions reduction potential from the non-EGU industries and emissions units. In the screening assessment, EPA used CoST to identify emissions units, emissions reductions, and associated compliance costs to evaluate the effects of potential non-EGU emissions control measures and technologies. CoST is designed to be used for illustrative control strategy analyses (*e.g.,* NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. The control cost estimates do not include monitoring, recordkeeping, reporting, or testing costs. This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs.

[a] EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-term emissions reductions. The analysis in the RIA assumes that the 2019 ozone season emissions will be the same in 2026 and later years.

For EGUs, the EPA analyzed ozone season NO_X emission reductions and the associated costs to the power sector using the Integrated Planning Model (IPM) and its underlying data and inputs. For non-EGUs, the EPA analyzed ozone season NO_X emission reductions and the associated costs for 2026 in the Non-EGU Screening Assessment memorandum. Table IX–3 reflects the estimates of the changes in the cost of supplying electricity for the regulatory control alternatives for EGUs and estimates of complying with the emissions limits for non-EGUs. For EGUs, compliance costs are negative in 2023. While seemingly counterintuitive, estimating negative compliance costs in a single year is possible given IPM's objective function is to minimize the discounted net present value (NPV) of a stream of annual total cost of generation over a multi-decadal time period. As such the model may undertake a compliance pathway that pushes higher costs later into the forecast period, since future costs are discounted more heavily than near term costs. This can result in a policy scenario showing single year costs that are lower than the Baseline, but over the entire forecast horizon, the policy scenario shows higher costs. For a detailed description of these cost trends, please see Chapter 4, Section 4.5.2 of the RIA. For a detailed description of the methods and results from Non-EGU Screening Assessment memorandum, see Chapter 4, Sections 4.4 and 4.5.2 of the RIA.

TABLE IX–3—TOTAL ESTIMATED COMPLIANCE COSTS (MILLION 2016$), 2023–2042

	Proposed rule	Less-stringent alternative	More-stringent alternative
2023:			
EGUs	−209	−173	−178
Non-EGUs	....	....	....
Total	−209	−173	−178
2026:			
EGUs	707	−406	1,180
Non-EGUs	411	357	445
Total	1,117	−49	1,625
2027:			
EGUs	1,544	1,540	1,983
Non-EGUs	411	357	445
Total	1,955	1,896	2,428
2030:			
EGUs	1,235	1,200	1,740
Non-EGUs	411	357	445
Total	1,646	1,557	2,185
2035:			
EGUs	1,729	1,596	2,335
Non-EGUs	411	357	445
Total	2,139	1,953	2,780
2042:			
EGUs	910	1,757	1,001
Non-EGUs	411	357	445
Total	1,321	2,114	1,446

Tables IX–4 and IX–5 report the estimated economic value of avoided premature deaths and illness in each year relative to the baseline along with the 95% confidence interval. In each of these tables, for each discount rate and regulatory control alternative, multiple benefits estimates are presented reflecting alternative ozone and $PM_{2.5}$ mortality risk estimates. For additional information on these benefits, see Chapter 5 of the RIA.

TABLE IX–4—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-ATTRIBUTABLE PREMATURE MORTALITY AND ILLNESS FOR THE PROPOSED POLICY SCENARIOS IN 2023

[95% Confidence interval; millions of 2016$] [a] [b]

Disc. rate	Pollutant	Proposal	More stringent alternative	Less stringent alternative
3%	Ozone Benefits	$57 ($15 to $120) [c] *and* $460 ($51 to $1,200) [d].	$65 ($17 to $140) [c] *and* $530 ($59 to $1,400) [d].	$57 ($15 to $120) [c] *and* $460 ($51 to $1,200). [d]
	PM Benefit Per Ton (BPT)s.	$44 *and* $45	$190 *and* $190	$59 *and* $60.
	Ozone Benefits plus PM BPTs.	$100 ($59 to $160) [c] *and* $500 ($96 to $1,200) [d].	$250 ($200 to $330) [c] *and* $720 ($250 to $1,600) [d].	$120 ($74 to $180) [c] *and* $520 ($110 to $1,300). [d]
7%	Ozone Benefits	$51 ($9.6 to 110) [c] *and* $410 ($42 to $1,100) [d].	$58 ($11 to $130) [c] *and* $480 ($49 to $1,300) [d].	$51 ($9.6 to $110) [c] *and* $410 ($42 to $1,100). [d]
	PM BPTs	$40 *and* $41	$170 *and* $170	$53 *and* $54.
	Ozone Benefits plus PM BPTs.	$90 ($49 to $150) [c] *and* $450 ($83 to $1,100) [d].	$230 ($180 to $300) [c] *and* $650 ($220 to $1,400) [d].	$100 ($63 to $170) [c] *and* $470 ($97 to $1,100). [d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated ozone benefits for changes in NO_X for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors for EGUs in 2023. This table does not include benefits from reductions for non-EGUs because reductions from these sources are not expected prior to 2026 when the proposed standards would become effective.
[c] Using the pooled short-term ozone exposure mortality risk estimate.
[d] Using the long-term ozone exposure mortality risk estimate.

TABLE IX–5—ESTIMATED DISCOUNTED ECONOMIC VALUE OF AVOIDED OZONE AND $PM_{2.5}$-ATTRIBUTABLE PREMATURE MORTALITY AND ILLNESS FOR THE PROPOSED POLICY SCENARIO IN 2026

[95% Confidence interval; millions of 2016$] [a] [b]

Disc. rate	Pollutant	Proposal	More stringent alternative	Less stringent alternative
3%	Ozone Benefits	$1,200 ($310 to $2,600) [c] *and* $10,000 ($1,100 to $26,000) [d].	$1,300 (340 to $2,900) [c] *and* $11,000 ($1,200 to $29,000) [d].	$830 ($210 to $1,800) [c] *and* $6,900 ($760 to $18,000). [d]
	PM BPTs	$8,100 *and* $8,300	$7,800 *and* $7,900	$3,400 *and* $3,500.
	Ozone Benefits plus PM BPTs.	$9,300 ($8,400 to $11,000) [c] *and* $18,000 ($9,400 to $35,000) [d].	$9,100 ($8,100 to $11,000) [c] *and* $19,000 ($9,200 to $37,000) [d].	$4,300 ($3,700 to $5,200) [c] *and* $10,000 ($4,300 to $22,000). [d]
7%	Ozone Benefits	$1,100 ($200 to $2,400) [c] *and* $9,000 ($920 to $24,000) [d].	$1,200 ($220 to $2,700) [c] *and* $10,000 ($1,000 to $26,000) [d].	$740 ($140 to $1,700) [c] *and* $6,200 ($630 to $16,000). [d]
	PM BPTs	$7,300 *and* $7,400	$7,000 *and* $7,100	$3,100 *and* $3,200.
	Ozone Benefits plus PM BPTs.	$8,400 ($7,500 to $9,700) [c] *and* $16,000 ($8,300 to $31,000) [d].	$8,200 ($7,200 to $9,700) [c] *and* $17,000 ($8,200 to $34,000) [d].	$3,800 ($3,200 to $4,800) [c] *and* $9,300 ($3,800 to $19,000). [d]

[a] Values rounded to two significant figures. The two benefits estimates are separated by the word "and" to signify that they are two separate estimates. The estimates do not represent lower- and upper-bound estimates and should not be summed.
[b] We estimated changes in NO_X for the ozone season and changes in $PM_{2.5}$ and $PM_{2.5}$ precursors in 2026. This table represents changes in EGU and non-EGU ozone season and annual controls.
[c] Sum of ozone mortality estimated using the pooled short-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.
[d] Sum of the Turner et al. (2016) long-term ozone exposure risk estimate and the Di et al. (2017) long-term $PM_{2.5}$ exposure mortality risk estimate.

In Tables IX–6, IX–7, and IX–8, EPA presents a summary of the monetized benefits, costs, and net benefits of the proposal and the more and less stringent alternatives for 2023, 2026, and 2030, respectively. The monetized benefits estimates do not include important climate benefits that were not monetized in the RIA. In addition, there are important water quality benefits and health benefits associated with reductions in concentrations of air pollutants other than $PM_{2.5}$ and ozone that are not quantified. We request comment on how to address the climate benefits and other categories of non-monetized benefits of the proposed rule. Discussion of the non-monetized health, climate, welfare, and water quality benefits is found in Chapter 5 of the RIA.

TABLE IX–6—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2023 FOR THE U.S.

[Millions of 2016$] [a] [b]

	Proposed rule	Less stringent alternative	More stringent alternative
Benefits [c] (3%)	$100 and $500	$120 and $520	$250 and $720.
Costs [d]	−$210	−$170	−$180.
Net Benefits	$310 and $710	$290 and $690	$430 and $900.
Benefits [c] (7%)	$90 and $450	$100 and $470	$230 and $650.
Costs [d]	−$210	−$170	−$180
Net Benefits	$300 and $660	$280 and $640	$400 and $820.

[a] We focus results to provide a snapshot of costs and benefits in 2023, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.
[b] Rows may not appear to add correctly due to rounding.

[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. *See Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[d] The costs presented in this table are 2023 annual estimates for each alternative analyzed. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

TABLE IX–7—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2026 FOR THE U.S.

[Millions of 2016$] [a b]

	Proposed rule	Less stringent alternative	More stringent alternative
Benefits [c] (3%)	$9,300 and $18,000	$4,300 and $10,000	$9,100 and $19,000.
Costs [d]	$1,100	−$49	$1,600.
Net Benefits	$8,200 and $17,000	$4,300 and $10,000	$7,500 and $17,000.
Benefits [c] (7%)	$8,400 and $16,000	$3,800 and $9,300	$8,200 and $17,000.
Costs [d]	$1,100	−$49	$1,600
Net Benefits	$7,300 and $15,000	$9,300 and $3,900	$6,600 and $15,000.

[a] We focus results to provide a snapshot of costs and benefits in 2026, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Rows may not appear to add correctly due to rounding.

[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposal conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[d] The costs presented in this table are 2026 annual estimates for each alternative analyzed. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

TABLE IX–8—MONETIZED BENEFITS, COSTS, AND NET BENEFITS OF THE PROPOSED AND LESS AND MORE STRINGENT ALTERNATIVES FOR 2030 FOR THE U.S.

(Millions of 2016$) [a b]

	Proposed rule	Less stringent alternative	More stringent alternative
Benefits [c] (3%)	$9,400 and $20,000	$4,300 and $11,000	$9,200 and $21,000.
Costs [d]	$1,600	$1,600	$2,200.
Net Benefits	$7,700 and $18,000	$2,800 and $9,700	$7,000 and $19,000.
Benefits [c] (7%)	$8,400 and $18,000	$3,900 and $10,000	$8,300 and $19,000.
Costs [d]	$1,600	$1,600	$2,200.
Net Benefits	$6,800 and $16,000	$2,300 and $8,400	$6,100 and $16,000.

[a] We focus results to provide a snapshot of costs and benefits in 2030, using the best available information to approximate social costs and social benefits recognizing uncertainties and limitations in those estimates.

[b] Rows may not appear to add correctly due to rounding.

[c] Monetized benefits include those related to public health associated with reductions in $PM_{2.5}$ and ozone concentrations. The health benefits are associated with several point estimates and are presented at a real discount rate of 3 percent. Several categories of benefits remain unmonetized and are thus not reflected in the table. Non-monetized benefits include important climate benefits from reductions in CO_2 emissions. The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposed rule conducted pursuant to E.O. 12866. Please see Chapter 5, Section 5.2 of the RIA for more discussion. In addition, there are important unquantified water quality benefits and benefits associated with reductions in other air pollutants.

[d] The costs presented in this table are 2030 annual estimates for each alternative analyzed. An NPV of costs was calculated using a 3.76% real discount rate consistent with the rate used in IPM's objective function for cost-minimization.

In addition, Table IX–9 presents estimates of the present value (PV) of the monetized benefits and costs and the equivalent annualized value (EAV), an estimate of the annualized value of the net benefits consistent with the present value, over the twenty-year period of 2023 to 2042. The estimates of the PV and EAV are calculated using discount rates of 3 and 7 percent as directed by OMB's Circular A–4 and are presented in 2016 dollars discounted to 2022.

TABLE IX–9—MONETIZED ESTIMATED BENEFITS, COMPLIANCE COSTS, AND NET BENEFITS OF THE PROPOSED RULE AND LESS AND MORE STRINGENT ALTERNATIVES, 2023 THROUGH 2042

(Millions 2016$, discounted to 2022) [a]

	3 Percent discount rate		7 Percent discount rate	
	PV	EAV	PV	EAV
Benefits				
Proposed Rule	$250,000	$17,000	$150,000	$14,000
Less Stringent Alternative	150,000	9,500	88,000	7,800
More Stringent Alternative	270,000	17,000	160,000	14,000
Compliance Costs				
Proposed Rule	22,000	1,500	14,000	1,300
Less Stringent Alternative	20,000	1,300	12,000	1,100
More Stringent Alternative	28,000	1,900	18,000	1,700
Net Benefits				
Proposed Rule	220,000	15,000	130,000	12,000
Less Stringent Alternative	120,000	8,100	70,000	6,600
More Stringent Alternative	230,000	15,000	130,000	12,000

[a] The U.S. District Court for the Western District of Louisiana has issued an injunction concerning the monetization of the benefits of greenhouse gas emission reductions by EPA and other defendants. See *Louisiana* v. *Biden,* No. 21–cv–01074–JDC–KK (W.D. La. Feb. 11, 2022). Therefore, such values are not presented in the benefit-cost analysis of this proposed rule conducted pursuant to E.O. 12866.

As shown in Table IX–9, the PV of the benefits of this proposed rule, discounted at a 3-percent discount rate, is estimated to be about $250,000 million, with an EAV of about $17,000 million. At a 7-percent discount rate, the PV of the benefits is estimated to be $150,000 million, with an EAV of about $14,000 million. The PV of the compliance costs, discounted at a 3-percent rate, is estimated to be about $22,000 million, with an EAV of about $1,500 million. At a 7-percent discount rate, the PV of the compliance costs is estimated to be about $14,000 million, with an EAV of about $1,300 million.

In addition to the analysis of costs and benefits, EPA also estimated the impacts on projected 2023 and 2026 ozone design values that are expected from the EGU and non-EGU control alternatives in this proposed rule. As described above, the alternative scenarios include the proposed rule along with scenarios that reflect less stringent and more stringent alternatives for EGUs and non-EGUs. The projected ozone design values and ozone impacts estimated in 2023 and 2026 for the proposed, less stringent, and more stringent alternatives are provided in Appendix 3B of the RIA. In summary, the differences in the amount of ozone reduction across the three alternatives at individual receptors in 2023 are consistent with the relative changes in NO_X emissions in this year under the different scenarios. Overall, in 2023 the estimated ozone reductions from all three of the alternatives are projected to be less than 0.1 ppb at most receptors. The exceptions are at certain receptors in Connecticut, Illinois, Texas, and Utah where impacts are between 0.1 and 0.2 ppb. In 2026, the largest impacts in the proposed rule are estimated at the two receptors in Texas (*i.e.,* Brazoria County and Harris County), where the average reduction is 1.3 ppb. Elsewhere in 2026, the average reductions for the proposed rule are on the order of 0.5 ppb at receptors in Connecticut, Illinois, and Wisconsin. The average reduction for the four receptors in Utah is approximately 0.3 ppb, while the average reduction at receptors in Colorado and California are approximately 0.2 ppb. Overall, the less stringent alternative provides approximately 0.1 to 0.3 ppb less ppb reduction (*i.e.,* 30 to 40 percent less reduction), on average, compared to the proposed rule at receptors in the East and in Colorado and Utah. The more stringent alternative does not appear to provide any notable additional ozone reductions compared to the proposed rule in all receptor areas, except at receptors in Connecticut and Texas where the average reduction increases by 0.1 ppb and 0.2 ppb with the more stringent alternative, respectively.

Examining the projected average and maximum design values in 2023 at individual receptors for the proposed, less stringent, and more stringent alternatives indicates that three of the receptors included in this impact analysis are projected to change attainment status in 2023 as a result of this proposed rule. Specifically, receptors in Clark County, Nevada, Butte County, California, and Riverside County Californian (Monitor ID: 060650008) are projected to switch from maintenance-only in the 2023 baseline to attainment and the receptor in Harris County, Texas is projected to switch from nonattainment to maintenance-only under any of the alternatives in 2023. In 2026, six of the receptors in this analysis are projected to change attainment status as a result of the emissions reductions in this proposed rule. Specifically, Calaveras County, California, Brazoria County, Texas, and in Kenosha County, Wisconsin (Monitor ID: 550590025) are projected to switch from maintenance-only to attainment in 2026 and a receptor in Riverside County, California (Monitor ID: 060650016) is projected to switch from nonattainment to maintenance under any of the alternatives. The receptor in Douglas County, Colorado and one of the receptors in Cook County, Illinois (Monitor ID: 170310076) are projected to switch from maintenance-only to attainment under the proposed and more stringent alternatives, but these receptors are projected to remain as maintenance-only in the less stringent alternative. The projected design values and additional information on the ozone impact analysis can be found in Appendix 3B of the proposed rule RIA.

X. Summary of Proposed Changes to the Regulatory Text for the Federal Implementation Plans and Trading Programs for EGUs

This section describes the proposed amendments to the regulatory text that would implement the proposed findings and remedy discussed elsewhere in this proposed rule with respect to EGUs. The primary CFR amendments would be revisions to the FIP provisions addressing states' good neighbor obligations related to ozone in 40 CFR part 52 as well as the revisions to the regulations for the CSAPR NO_X Ozone Season Group 3 Trading Program in 40 CFR part 97, subpart GGGGG. In conjunction with the amendments to the Group 3 trading program, the monitoring, recordkeeping, and reporting regulations in 40 CFR part 75 would be amended to reflect the addition of certain new reporting requirements associated with the amended trading program and the administrative appeal provisions in 40 CFR part 78 would be amended to identify certain additional types of appealable decisions of the EPA Administrator under the amended trading program. The proposed provisions to address the transition of the EGUs in certain states from the Group 2 trading program to the Group 3 trading program would be implemented in part through revisions to regulations noted above and in part through revisions to the regulations for the Group 2 trading program in 40 CFR part 97, subpart EEEEE.

In addition to these primary amendments, certain revisions are proposed to the regulations for the other CSAPR trading programs in 40 CFR part 97, subparts AAAAA through EEEEE, and the Texas SO_2 Trading Program in 40 CFR part 97, subpart FFFFF, for conformity with the proposed amended provisions of the Group 3 trading program, as discussed in Section VII.B.12 of this proposed rule. Documents have been included in the docket for this proposed rule showing all of the proposed revisions in redline-strikeout format.

A. Amendments to FIP Provisions in 40 CFR Part 52

The CSAPR, CSAPR Update, and Revised CSAPR Update FIP requirements related to ozone season NO_X emissions are set forth in 40 CFR 52.38(b) as well as other sections of part 52 specific to each covered state. The existing text of § 52.38(b)(1) identifies the trading program regulations in 40 CFR part 97, subparts BBBBB, EEEEE, and GGGGG as constituting the relevant FIP provisions relating to seasonal NO_X emissions and transported ozone pollution. Because the EPA is proposing in this rulemaking to establish new or amended FIP requirements not only for the types of EGUs covered by the trading programs but also for other types of sources, a proposed amendment to § 52.38(b)(1) would clarify that the trading programs constitute the FIP provisions only for the sources meeting the applicability requirements of the trading programs. A parallel clarification would be added to §§ 52.38(a)(1) and 52.39(a) with respect to the CSAPR FIP requirements relating to annual NO_X emissions, SO_2 emissions, and transported fine particulate pollution.

The states whose EGU sources are required to participate in the CSAPR NO_X Ozone Season Group 1, Group 2, and Group 3 trading programs under the FIPs established in CSAPR, the CSAPR Update, and the Revised CSAPR Update, as well as the control periods for which those requirements apply, are identified in § 52.38(b)(2). Proposed amendments to this paragraph would expand the applicability of the Group 3 trading program to sources in the thirteen additional states that the EPA is proposing to add to the Group 3 trading program starting with the 2023 control period and would end the applicability of the Group 2 trading program (with the exception of certain provisions) for sources in eight of the thirteen states after the 2022 control period, as discussed in Section VII.B.2 of this proposed rule.[339] The current subparagraphs within § 52.38(b)(2) would also be renumbered to clarify the organization of the provisions and to facilitate cross-references from other regulatory provisions. Regarding the two states currently participating in the Group 2 trading program through approved SIP revisions that replaced the previous FIPs issued under the CSAPR Update (Alabama and Missouri), a provision indicating that EPA would no longer administer the state trading programs adopted under those SIP revisions after the 2022 control period would be added at § 52.38(b)(16)(ii)(B).

In the Revised CSAPR Update, the EPA established several options for states to revise their SIPs to modify or replace the FIPs applicable to their sources while continuing to use the Group 3 trading program as the mechanism for meeting the states' good neighbor obligations. Existing § 52.38(b)(10), (11), and (12) establish options to replace allowance allocations for the 2022 control period, to adopt an abbreviated SIP revision for control periods in 2023 or later years, and to adopt a full SIP revision for control periods in 2023 or later years, respectively. As discussed in Section VII.D of this proposed rule, the EPA is proposing to retain these SIP revision options and to make them available for all states that would be covered by the Group 3 trading program after the proposed geographic expansion. The option under § 52.38(b)(10) to replace allowance allocations for a single control period would be amended to be available for the 2024 control period, with attendant revisions to the years and dates shown in § 52.38(b)(10) (multiple paragraphs) and (b)(17)(i) as well as the Group 3 trading program regulations, as discussed in Section X.B of this proposed rule. The options under § 52.38(b)(11) and (12) to adopt abbreviated or full SIP revisions would be amended to be available starting with the 2025 control period, with attendant revisions to § 52.38(b)(11)(iii), (b)(12)(iii), and (b)(17)(ii).[340]

The proposed changes with respect to set-asides, the treatment of units in Indian country, and recordation schedules discussed in Section VII.B.9 of this proposed rule, although implemented largely through proposed amendments to the Group 3 trading program regulations, would also be implemented in part through proposed amendments to § 52.38(b)(11) and (12). First, the text in § 52.38(b)(11)(iii)(A) and (b)(12)(iii)(A) identifying the portion of each state trading budget for which a state could establish state-determined allowance allocations would be revised to exclude any allowances in a new unit set-aside, Indian country new unit set-aside, or Indian country existing unit set-aside. Second, the text in § 52.38(b)(12)(vi) identifying provisions that states could not adopt into their SIPs (because the provisions concern regulation of sources in Indian country not subject to a state's CAA implementation planning authority) would be revised to include the provisions of the amended Group 3 trading program addressing allocation and recordation of allowances from all types of set-asides. Third, the text in § 52.38(b)(12)(vii) authorizing the EPA to modify the previous approval of a SIP revision with regard to the assurance provisions ''if and when a covered unit is located in Indian country'' would be revised to account for the fact that at least one covered unit would already be located in Indian country not subject to a state's jurisdiction if the geographic expansion proposed in this rulemaking

[339] Both the current text of § 52.38(b)(2) and the proposed amended text expressly encompass sources in Indian country within the respective states' borders.

[340] No state currently in the Group 3 trading program has submitted a SIP revision to make use of these options in control periods before the control periods in which the options could be used under the proposed amendments.

is finalized. Finally, the text in § 52.38(b)(11)(iii)(B) and (b)(12)(iii)(B) would be revised to amend the deadline for states to submit state-determined allowance allocations to the EPA from June 1 in the third year before the relevant control period to June 1 in the year before the relevant control period.

The proposed transitional provisions discussed in Section VII.B.11 of this proposed rule to convert certain 2017–2022 Group 2 allowances to Group 3 allowances and to recall certain 2023–2024 Group 2 allowances, although promulgated as amendments to the Group 2 trading program regulations, would necessarily be implemented after the end of the 2022 control period. Proposed amendments clarifying that these provisions continue to apply to the relevant sources and holders of allowances notwithstanding the transition of certain states out of the Group 2 trading program after the 2022 control period would be added at § 52.38(b)(14)(iii)(F) and (G). Cross-references clarifying that EPA's allocations of the converted Group 3 allowances would not be subject to modification through SIP revisions would also be added to the existing provisions at § 52.38(b)(11)(iii)(D) and (b)(12)(iii)(D).

The general FIP provisions applicable to all states covered by this proposed rule as set forth in § 52.38(b)(2) would be replicated in the state-specific subparts of 40 CFR part 52 for each of the thirteen states that the EPA is proposing to add to the Group 3 trading program.[341] In each such state-specific CFR subpart, provisions would be added indicating that sources in the state are required to participate in the CSAPR NO_X Ozone Season Group 3 Trading Program with respect to emissions starting in 2023. Provisions would also be added repeating the substance of § 52.38(b)(13)(i), which generally provides that the Administrator's full and unconditional approval of a full SIP revision correcting the same SIP deficiency that is the basis for a FIP promulgated in this rulemaking would cause the FIP to no longer apply to sources subject to the state's CAA implementation planning authority, and § 52.38(b)(14)(ii), which generally provides the EPA with authority to complete recordation of EPA-determined allowance allocations for any control period for which EPA has already started such recordation notwithstanding the approval of a state's SIP revision establishing state-determined allowance allocations.

For each of the eight states that the EPA is proposing to remove from the Group 2 trading program, the current provisions of the state-specific CFR subparts indicating that sources in the state are required to participate in that trading program would be revised to end that requirement with respect to emissions after 2022, and a further provision would be added repeating the substance of § 52.38(b)(14)(iii), which identifies certain provisions that continue to apply to sources and allowances notwithstanding discontinuation of a trading program with respect to a particular state.[342] In addition, for the six states that during their time in the Group 2 trading program have not exercised the option to adopt full SIP revisions to replace the FIPs issued under the CSAPR Update (all but Alabama and Missouri), obsolete provisions concerning the unexercised SIP revision option would be removed.

No amendments with respect to FIP requirements for EGUs would be made to the state-specific CFR subparts for the twelve states whose sources currently participate in the Group 3 trading program[343] except as needed to update cross-references or to implement the proposed changes related to the treatment of Indian country, as discussed in Section X.D of this proposed rule.

B. Amendments to Group 3 Trading Program and Related Regulations

To implement the geographic expansion of the Group 3 trading program and the revised trading budgets that would be established under the new and amended FIPs proposed in this rulemaking, several sections of the Group 3 trading program regulations would be amended. Revisions identifying the applicable control periods, deadlines for certification of monitoring systems, and deadlines for commencement of quarterly reporting for sources not previously covered by the Group 3 trading program would be made at §§ 97.1006(c)(3)(i), 97.1030(b)(1), and 97.1034(d)(2)(i), respectively. Revisions identifying the proposed new or revised budgets and new unit set-asides for the 2023 and 2024 control periods for all covered states would be made at § 97.1010(a)(1) and (b)(1), respectively.

Each of the proposed enhancements to the Group 3 trading program discussed in Section VII.B of this proposed rule would also be implemented primarily through revisions to the trading program regulations. The dynamic budget-setting process discussed in Section VII.B.4 of this proposed rule would be implemented at § 97.1010(a)(2) and (3), and the associated revised process for determining variability limits and assurance levels discussed in Section VII.B.5 of this proposed rule would be implemented at § 97.1010(e). The Group 3 allowance bank recalibration process discussed in Section VII.B.6 of this proposed rule would be implemented at § 97.1026(d). The backstop daily NO_X emissions rate component of the primary emissions limitation discussed in Section VII.B.7 would be implemented at §§ 97.1006(c)(1)(i) and 97.1024(b)(1) and (3), accompanied by the addition of a definition of ''backstop daily NO_X emissions rate'' and modification of the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'' in § 97.1002. The secondary emissions limitation for sources found responsible for exceedances of the assurance levels discussed in Section VII.B.8 of this proposed rule would be implemented at §§ 97.1006(c)(1)(iii) and (iv) and (c)(3)(ii) and 97.1025(c), accompanied by the addition of a definition of ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'' in § 97.1002.

The proposed changes relating to set-asides, the treatment of Indian country, unit-level allowance allocations, and recordation schedules discussed in Section VII.B.9 of this proposed rule would be implemented through revisions to multiple sections of §§ 97.1010, 97.1011, 97.1012, and 97.1021, as well as limited revisions to 97.1002 (definition of ''allocate or allocation'') and 97.1006(b)(2). In § 97.1010, paragraphs (b), (c), and (d) would address the amounts for each control period of the new unit set-asides, Indian country new unit set-asides, and Indian country existing unit set-asides, respectively. Paragraphs (c) and (d) would reflect the discontinuation of Indian country new unit set-asides after the 2022 control period and the establishment of Indian

[341] *See* proposed §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.440(d) (Delaware), 52.1240(d) (Minnesota), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1492 (Nevada), 52.1930(a) (Oklahoma), 52.2240(e) (Tennessee), 52.2283(d) (Texas), 52.2356 (Utah), 52.2587(e) (Wisconsin), and 52.2638(a) (Wyoming).

[342] *See* proposed §§ 52.54(b) (Alabama), 52.184(a) (Arkansas), 52.1824(a) (Mississippi), 52.1326(b) (Missouri), 52.1930(a) (Oklahoma), 52.2240(e) (Tennessee), 52.2283(d) (Texas), and 52.2587(e) (Wisconsin).

[343] *See* proposed §§ 52.731(b) (Illinois), 52.789(b) (Indiana), 52.940(b) (Kentucky), 52.984(d) (Louisiana), 52.1084(b) (Maryland), 52.1186(e) (Michigan), 52.1584(e) (New Jersey), 52.1684(b) (New York), 52.1882(b) (Ohio), 52.2040(b) (Pennsylvania), 52.2440(b) (Virginia), and 52.2540(b) (West Virginia).

country existing unit set-asides starting with the 2023 control period.[344]

The proposed revisions to § 97.1011 would refocus the section exclusively on allocation to ''existing'' units from the portion of each state emissions budget not reserved in a new unit set-aside or Indian country new unit set-aside. In § 97.1011(a), the provision currently in § 97.1011(a)(1) requiring allocations to existing units to be made in the amounts provided in notices of data availability (NODAs) issued by the EPA would be split into two separate provisions, with paragraph (a)(1) applying to existing units in the state and areas of Indian country covered by the state's CAA implementation planning authority and paragraph (a)(2) applying to existing units in areas of Indian country not covered by the state's CAA implementation planning authority.[345] This split would facilitate the submission and approval of SIP revisions by states interested in submitting state-determined allowance allocations for the units over which they exercise CAA implementation authority, while leaving allocations to any units outside their authority to be addressed either by the EPA or by the relevant tribe under an approved tribal implementation plan. The proposed dynamic process for determining default allocations to existing units of allowances from state trading budgets starting with the 2025 control period would be set forth in revised § 97.1011(b), while the current provisions of § 97.1011(b), which concern timing and notice procedures for allocations to new units, would be relocated to § 97.1012. The provisions addressing incorrectly allocated allowances at § 97.1011(c) would be streamlined by relocating the portions applicable to new units to § 97.1012(c). In addition, as discussed in Section VII.B.9.d of this proposed rule, § 97.1011(c)(5) would be revised to provide that, starting with the 2024 control period, any incorrectly allocated allowances recovered after May 1 of the year following the control period would not be reallocated to other units in the state but instead would be transferred to a surrender account.

The proposed revisions to § 97.1012 would retain the section's current focus on allocations to ''new'' units, generally combining the current provisions at § 97.1012 with the current provisions at § 97.1011(b) and (c) that address new units. The text of multiple paragraphs in both § 97.1012(a) and (b) would be revised as needed to reflect the change in treatment of Indian country discussed in Section VII.B.9.a of this proposed rule, under which the new unit set-asides would be used to provide allowance allocations to new units both in non-Indian country and Indian country within the borders of the respective states for control periods starting in 2023.[346] The timing and notice provisions in proposed § 97.1012(a)(13) and (b)(13) are relocated from current § 97.1011(b)(1) and (2). The text of § 97.1012(c), addressing incorrect allocations to new units, is largely relocated from § 97.1011(c) (which addresses incorrect allocations to existing units) and reflects a parallel proposed revision addressing the disposition of recovered allowances, as discussed in Section VII.B.9.d of this proposed rule.

The proposed amendments to § 97.1021 would implement three distinct sets of changes discussed in Sections VII.B.9 and VII.D.1 of this proposed rule. First, revisions to § 97.1021(b) through (e) would replace the previous schedule for recording Group 3 allowances for the 2023 and 2024 control periods established in the Revised CSAPR Update with an updated recordation schedule tailored to the expected timing for issuance of a final rule in this rulemaking. The updated schedule would also reflect elimination of the unused former option for states to provide state-determined allowance allocations for the 2022 control period and the proposed establishment of a substantively equivalent new option for states to provide state-determined allowance allocations for the 2024 control period. Second, revisions to § 97.1021(f) would change the schedule for recording allocations to existing units for future control periods from July 1 of the year three years before the control period to July 1 of the year before the control period. Finally, revisions to § 97.1021(g) through (j) would end recordation for Indian country new unit set-asides after allocations for the 2022 control period, begin recordation for Indian country existing unit set-asides starting with allocations for the 2023 control period, and modify the text to eliminate references to state-determined allocations of allowances from new unit set-asides.

Implementation of the proposed revisions to the Group 3 trading program would also be accomplished in part through amendments to regulations in other CFR parts. In 40 CFR part 75, which contains detailed monitoring, recordkeeping, and reporting requirements applicable to sources covered by the Group 3 trading program, the additional recordkeeping and reporting requirements discussed in Section VII.B.10.b of this proposed rule would be implemented through the addition of §§ 75.72(f) and 75.73(f)(1)(ix) and (x) and revisions to § 75.75, and the procedures for calculating daily total heat input and daily total NO_X emissions and for apportioning NO_X mass emissions monitored at a common stack among the individual units using the common stack would be added at sections 5.3.3, 8.4(c), and 8.5.3 of appendix F to part 75. In 40 CFR part 78, which contains the administrative appeal procedures applicable to decisions of the EPA Administrator under the Group 3 trading program, § 78.1(b)(19) would be amended to list additional decisions made as part of the trading program enhancements that would be appealable under those procedures.

C. Transitional Provisions

As discussed in Section VII.D.11 of this proposed rule, the EPA is proposing several transitional provisions for sources entering the Group 3 trading program. The provisions discussed in Section VII.D.11.a of this proposed rule, concerning the prorating of state emissions budgets, assurance levels, and unit-level allocations for the 2023 control period, would be implemented through the Group 3 trading program regulations. Specifically, the state emissions budgets for the 2023 control period would be prorated according to procedures set out at § 97.1010(a)(1)(ii). Variability limits for the 2023 control period, and the resulting assurance levels, would be computed under § 97.1010(e) from the prorated state emissions budgets. Unit-level

[344] The current § 97.1011(c), which addresses the relationships of set-asides and variability limits to state trading budgets, would be relocated to § 97.1011(f).

[345] An additional provision currently in § 97.1011(a)(1), which clarifies that an allocation or lack of allocation to a unit in a NODA does not constitute a determination by the EPA that the unit is or is not a CSAPR NO_X Ozone Season Group 3 unit, would be relocated to § 97.1011(a)(3). The current § 97.1011(a)(2), which provides for certain existing units that cease operations to receive allocations for their first five control periods of non-operation and provides for the allowances for subsequent control periods to be allocated to the relevant state's new unit set-asides, is inconsistent with the proposed revisions to the set-asides and the default allowance allocation process, as discussed in Section VII.B.9 of this proposed rule, and would be removed as obsolete.

[346] Revisions are also proposed to the text of § 97.1012(a) and (b) for the control periods in 2021 and 2022 consistent with the proposed revisions to the parallel provisions in the regulations for the other CSAPR trading programs, generally calling for allocations to units in areas of Indian country subject to a state's CAA implementation planning authority to be made from the new unit set-asides instead of from the Indian country new unit set-asides.

allocations to existing units for the 2023 control period would be computed from the prorated state emissions budgets according to procedures substantively the same as the procedures codified in § 97.1011(b) for calculating default allocations to existing units for later control periods, as discussed in Section VII.B.9.b of this proposed rule, and would be announced in the notice of data availability issued under § 97.1011(a)(1) and (2) for the 2023 and 2024 control periods.

The remaining transitional provisions would be implemented through the Group 2 trading program regulations. The creation of an additional Group 3 allowance bank for the 2023 control period through the conversion of banked 2017–2022 Group 2 allowances as discussed in Section VII.B.11.b of this document would be implemented at § 97.826(e).[347] Related provisions addressing the use of Group 3 allowances to satisfy after-arising compliance obligations under the Group 2 trading program or the Group 1 trading program would be implemented at §§ 97.826(f)(2) and 97.526(e)(3), respectively, and related provisions addressing recordation of late-arising allocations of Group 1 allowances would be implemented at § 97.526(d)(2)(iii). The recall of Group 2 allowances previously issued for the 2023 and 2024 control periods as discussed in Section VII.B.11.c of this document would be implemented at § 97.811(e).

Decisions of the Administrator related to the allowance bank creation provisions and the allowance recall provisions would be identified as appealable decisions under 40 CFR part 78 through revisions to § 78.1(b)(17)(viii) and (ix).

D. Clarifications and Conforming Revisions

As discussed in Section VII.B.12 of this proposed rule, the EPA is proposing to make revisions to the provisions regarding allowance allocations for units in Indian country in all the CSAPR trading programs so that instead of distinguishing among units based on whether they are or are not located in Indian country, the revised provisions would distinguish among units based on whether they are or are not covered by a state's CAA implementation planning authority. The proposed revisions would be implemented in multiple paragraphs of §§ 97.411(b), 97.412, 97.511(b), 97.512, 97.611(b), 97.612, 97.711(b), 97.712, 97.811(b), and 97.812. The associated revisions to states' options regarding SIP revisions to establish state-determined allowance allocations for units covered by their CAA implementation planning authority would be implemented in multiple paragraphs of §§ 52.38(a) and (b) and 52.39 as well as the state-specific subparts of 40 CFR part 52.

As also discussed in Section VII.B.12 of this proposed rule, the EPA is proposing to revise the recordation schedule for allowance allocations to existing units under all the CSAPR trading programs, as well as the Texas SO_2 Trading Program, so that starting with the 2025 control period the allocation deadline would generally be July 1 of the year before the control period instead of July 1 of the year 3 years before the control period. The revisions would be implemented at §§ 97.421(f)(2), 97.521(f)(2), 97.621(f)(2), 97.721(f)(2), 97.821(f), and 97.921(b)(2).

Certain other revisions to the regulatory text in the FIP and trading program regulations are proposed as non-substantive clarifications. First, in the Group 2 trading program regulations, the paragraphs in § 97.810 setting forth the amounts of state emissions budgets, new unit set-asides, Indian country new unit set-asides, and variability limits for states that the EPA is proposing to transition out of the Group 2 trading program would be modified to indicate that the amounts are applicable under that program only for control periods through 2022.

Second, as noted in Section VII.F.1 of this proposed rule, the existing option for states subject to the NO_X SIP Call to expand applicability of the Group 2 trading program to include certain large non-EGU boilers and combustion turbines would become obsolete if this rule is finalized as proposed because no NO_X SIP Call states would continue to be covered by the Group 2 trading program. The proposed elimination of the obsolete option would be implemented in part through revisions to § 52.38(b)(8) (multiple paragraphs), (b)(9) (multiple paragraphs), (b)(13)(ii), (b)(14)(i)(F), and (b)(16)(i)(B), and in part through revisions to the Group 2 trading program regulations at §§ 97.806(c)(2) and (3), 97.825, and 97.802 (removal of the definitions of ''base CSAPR NO_X Ozone Season Group 2 source'' and ''base CSAPR NO_X Ozone Season Group 2 unit'' and modification of the definitions of ''assurance account'', ''common designated representative'', common designated representative's assurance level'', and ''common designated representative's share'').

Third, to clarify the regulatory text, the EPA is proposing to remove the language in the Group 3 trading program regulations finalized in the Revised CSAPR Update relating to the ''supplemental allowances'' issued for the 2021 control period in current §§ 97.1002 (definition of ''common designated representative's assurance level''), 97.1006(c)(2)(iii), 97.1010(d), and 97.1011(a)(1). In place of the removed language, the EPA proposes to restate the amounts of the state emissions budgets for the 2021 control period in § 97.1010(a)(1)(i) so as to include the amounts of the supplemental allowances in the restated budget amounts. The revised language would be substantively equivalent to and simpler than the current language.

Fourth, in 40 CFR part 75, the EPA proposes to remove obsolete text in § 75.73(c) and (f) to clarify the context for other text that would be added to the section, as discussed in Section X.B.

Finally, the EPA proposes to update cross-references throughout 40 CFR parts 52 and 97 for consistency with the other amendments proposed in this rulemaking.

XI. Statutory and Executive Orders Reviews

Additional information about these statutes and Executive Orders (''E.O.'') can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders*.

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed rule is an economically significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review. This proposed rule is in response to a court-ordered legal mandate and proposes to implement EGU and novel non-EGU NO_X ozone season emissions reductions as part of the overall strategy for addressing interstate transport of ozone pollution for the 2015 ozone NAAQS. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this proposed rule. This analysis, which is contained in the ''Regulatory Impact Analysis for the Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard'' [EPA–452/R–15–009], is available in the docket and is briefly summarized in Section IX of this proposed rule.

[347] The current provisions at § 97.826(e) would be relocated to § 97.826(f)(1) and (3).

B. Paperwork Reduction Act (PRA)

1. Information Collection Request for Electric Generating Units

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2709.01. EPA has placed a copy of the ICR in the docket for this rule, and it is briefly summarized here.

EPA is proposing an information collection request (ICR), related specifically to electric generating units (EGU), for the proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard. The proposed rule would amend the Cross-State Air Pollution Rule (CSAPR) NO_X Ozone Season Group 3 trading program addressing seasonal NO_X emissions in various states. Under the proposed amendments, all EGU sources in the original twelve Group 3 states (Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, New Jersey, New York, Ohio, Pennsylvania, Virginia, and West Virginia) would remain. Additionally, EGU sources in eight states (Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin) currently covered by the CSAPR NO_X Ozone Season Group 2 Trading Program would transition from the Group 2 program to the revised Group 3 trading program beginning with the 2023 ozone season. Further, sources in five states not currently covered by any CSAPR NO_X ozone season trading program would join the revised Group 3 trading program: Delaware, Minnesota, Nevada, Utah, and Wyoming. In total, EGU sources in 25 states would now be covered by the Group 3 program.

There is an existing ICR (OMB Control Number 2060–0667), that includes information collection requirements placed on EGU sources for the six Cross-State Air Pollution Rule (CSAPR) trading programs addressing sulfur dioxide (SO_2) emissions, annual nitrogen oxides (NO_X) emissions, or seasonal NO_X emissions in various sets of states, and the Texas SO_2 trading program which is modeled after CSAPR. This ICR accounts for the additional respondent burden related to the amendments to the CSAPR NO_X Ozone Group 3 trading program.

The principal information collection requirements under the CSAPR and Texas trading programs relate to the monitoring and reporting of emissions and associated data in accordance with 40 CFR part 75. Other information collection requirements under the programs concern the submittal of information necessary to allocate and transfer emission allowances and the submittal of certificates of representation and other typically one-time registration forms.

Affected sources under the CSAPR and Texas trading programs are generally stationary, fossil fuel-fired boilers and combustion turbines serving generators larger than 25 megawatts (MW) producing electricity for sale. Most of these affected sources are also subject to the Acid Rain Program (ARP). The information collection requirements under the CSAPR and Texas trading programs and the ARP substantially overlap and are fully integrated. The burden and costs of overlapping requirements are accounted for in the ARP ICR (OMB Control Number 2060–0258). Thus, this ICR accounts for information collection burden and costs under the CSAPR NO_X Ozone Season Group 3 trading program that are incremental to the burden and costs already accounted for in both the ARP and CSAPR ICRs.

For most sources already reporting data under the CSAPR NO_X Ozone Season Group 3 or CSAPR NO_X Ozone Group 2 trading programs, there would be no incremental burden or cost, as reporting requirements will remain identical. Certain sources with a common stack configuration and/or those that are large, coal-fired EGUs, will be subject to additional emission reporting requirements under the proposed rule. These sources will need to make a one-time monitoring plan and Data Acquisition and Handling System (DAHS) update to meet the additional reporting requirements. Remaining for assessment of incremental cost and burden are only those sources in the five states not currently reporting data under a CSAPR NO_X Ozone Season program. Sources in Minnesota are already reporting data for the CSAPR NO_X Annual program with almost identical information collection requirements, requiring only a one-time monitoring plan and DAHS update. Most of the affected sources in Delaware, Nevada, Utah, and Wyoming are already reporting data as part of the Acid Rain Program, thus only requiring a monitoring plan and DAHS update as well. Four additional EGUs in Delaware already report data under SIP requirements adopted to meet the NO_X SIP Call and would face identical information requirements under this proposed rule. For the units that already report to EPA under the Acid Rain Program or the NO_X SIP Call, with the exception of any one-time costs to update monitoring plans and DAHS, all information collection costs and burden are already reflected in the previously approved ICRs for those other rules (OMB Control Nos. 2060–0258 and 2060–0445).

In total, there are an estimated 16 units in Delaware, Nevada, Utah, and Wyoming that do not already report data to EPA according to 40 CFR part 75 and that would need to implement one of the Part 75 monitoring methodologies including certification of monitoring systems or implementation of the low mass emissions methodology. These units would also require monitoring plan and DAHS updates. Of these sixteen units, two units would be expected to adopt low mass emissions (LME) as the monitoring method, thirteen would be expected to adopt Appendix D monitoring methods, and one would be expected to adopt CEMS monitoring methods.

Respondents/affected entities: Industry respondents are stationary, fossil fuel-fired boilers and combustion turbines serving electricity generators subject to the CSAPR and Texas trading programs, as well as non-source entities voluntarily participating in allowance trading activities. Potential state respondents are states that can elect to submit state-determined allowance allocations for sources located in their states.

Respondent's obligation to respond: Industry respondents: Voluntary and mandatory (Sections 110(a) and 301(a) of the Clean Air Act).

Estimated number of respondents: EPA estimates that there would be 188 industry respondents.

Frequency of response: On occasion, quarterly, and annually.

Total estimated additional burden: 1,834 hours (per year). Burden is defined at 5 CFR 1320.03(b).

Total estimated additional cost: \$396,520 (per year); includes \$210,571 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to

OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than May 6, 2022. The EPA will respond to any ICR-related comments in the final rule.

2. Information Collection Request for Non-Electric Generating Units

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 2705.01. The EPA has filed a copy of the non-EGU ICR in the docket for this rule, and it is briefly summarized here.

ICR No. 2705.01 is a new request and it addresses the burden associated with new regulatory requirements under the proposed rule. Owners and operators of certain non-Electric Generating Unit (non-EGU) industry stationary sources will potentially modify or install new emission controls and associated monitoring systems to meet the nitrogen oxides (NO_X) emission limits of this proposed rule. The burden in this ICR reflects the new monitoring, calibrating, recordkeeping, reporting and testing activities required by industry and the administrative review conducted by the states of the associated industry activities. This information is being collected to assure compliance with the proposed rule. In accordance with the Clean Air Act Amendments of 1990, any monitoring information to be submitted by sources is a matter of public record. Information received and identified by owners or operators as confidential business information (CBI) and approved as CBI by EPA, in accordance with Title 40, Chapter 1, Part 2, Subpart B, shall be maintained appropriately (see 40 CFR 2; 41 FR 36902, September 1, 1976; amended by 43 FR 39999, September 8, 1978; 43 FR 42251, September 28, 1978; 44 FR 17674, March 23, 1979).

Respondents/affected entities: The respondents/affected entities are the owners/operators of certain non-EGU industry sources in the following industry sectors: Furnaces in Glass and Glass Product Manufacturing; boilers and furnaces in Iron and Steel Mills and Ferroalloy Manufacturing; kilns in Cement and Cement Product Manufacturing; reciprocating internal combustion engines in Pipeline Transportation of Natural Gas; and high-emitting equipment and large boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mill.

Respondent's obligation to respond: Voluntary and mandatory. (Sections 110(a) and 301(a) of the Clean Air Act). All data that is recorded or reported by respondents is required by the proposed rule, titled ''Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units''.

Estimated number of respondents: 489.

Frequency of response: The specific frequency for each information collection activity within the non-EGU ICR is shown at the end of the ICR document in the Tables 1–11. In general, the frequency varies across the monitoring, recordkeeping, and reporting activities. Some recordkeeping such as work plan preparation is a one-time activity whereas engine maintenance recordkeeping is conducted quarterly. Reporting frequency is on a quarterly and semi-annual basis.

Total estimated burden: 51,654 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $11,450,000 (average per year); includes $5,467,000 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information from the EGU ICR and non-EGU ICR, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *OIRA_submission@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than May 6, 2022. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

The EPA certifies that this proposed action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (RFA). The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. 104–121), provides that whenever an agency is required to publish a general notice of proposed rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the proposed rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. 605(b)). Small entities include small businesses, small organizations, and small governmental jurisdictions.

In 2026, EPA identified 34 small entities affected by the proposed rule, and of these 6 small entities may experience costs of greater than 1 percent of revenues. Of the 6 small entities projected to have costs greater than 1 percent of revenues, two of them operate in cost-of-service regions and would generally be able to pass any increased costs along to rate-payers. In EPA's modeling, most of the cost impacts for these small entities and their associated units are driven by lower electricity generation relative to the base case baseline. Specifically, four units reduce their generation by significant amounts, driving the bulk of the costs for all small entities. Finally, EPA's decision to exclude units smaller than 25 MW capacity from the proposed FIP, and exclusion of uncontrolled units smaller than 100 MW from backstop emission rate limits has already significantly reduced the burden on small entities by reducing the number of affected small entity-owned units. Further, in 2026 for non-EGUs, there are five small entities, and one small entity is estimated to have a cost-to-sales impact of 1.3 percent of their revenues.

The EPA has determined that an insignificant number of small entities potentially affected by the proposed rule will have compliance costs greater than 1 percent of annual revenues during the compliance period. EPA has concluded that there will be no significant economic impact on a substantial number of small entities (No SISNOSE) for this proposed rule overall. Details of this analysis are presented in Chapter 6 of the RIA, which is in the public docket.

D. Unfunded Mandates Reform Act (UMRA)

This proposed action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and will not significantly or uniquely affect small governments. Note that we expect the proposed rule to potentially have an impact on only one category of government-owned entities (municipality-owned entities). This analysis does not examine potential indirect economic impacts associated with the proposed rule, such as employment effects in industries providing fuel and pollution control equipment, or the potential effects of electricity price increases on government entities. For more information on the estimated impact on government entities, refer to the RIA, which is in the public docket.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. If finalized, this proposed action will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This proposed action has tribal implications. However, it would neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law.

The EPA proposes to make a finding that interstate transport of ozone precursor emissions from 26 upwind states (Alabama, Arkansas, California, Delaware, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming) is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states, based on projected nitrogen oxides (NO_X) emissions in the 2023 ozone season. EPA is proposing to issue FIP requirements to eliminate interstate transport of ozone precursors from these 26 states that significantly contributes to nonattainment or interferes with maintenance of the NAAQS in other states. Under CAA section 301(d)(4), EPA proposes to extend FIP requirements to apply in Indian country located within the upwind geography of the proposed rule, including Indian reservation lands and other areas of Indian country over which EPA or a tribe has demonstrated that a tribe has jurisdiction. EPA's proposed extension is described further above in Section IV.C.2., *Application of Rule in Indian Country and Necessary or Appropriate Finding.* EPA proposes that all existing and new EGU and non-EGU sources that are located in the 301(d) FIP areas within the geographic boundaries of the covered states, and which would be subject to this rule if located within areas subject to state CAA planning authority, should be included in this rule. This proposed action has tribal implication because of the proposed extension of FIP requirements into Indian country and this proposed rule may have additional tribal implications if a new affected EGU or non-EGU is built in Indian country. To EPA's knowledge, only one existing EGU or non-EGU source is located within the 301(d) FIP areas: The Bonanza Power Plant, an EGU source, located on the Uintah and Ouray Reservation, geographically located within the borders of Utah. In general, tribes have a vested interest in how this proposed rule would affect air quality.

In the Revised CSAPR Update, EPA established default procedures for allocating CSAPR NO_X Ozone Season Group 3 allowances (''Group 3 allowances'') in amounts equal to each state emissions budget for each control period among the sources in the state for use in complying with the Group 3 trading program. Under the current Group 3 trading programs, reserved allowances are made available generally (but not exclusively [348]) to ''new'' units—which for purposes of the Revised CSAPR Update means units commencing commercial operation on or after January 1, 2019—through a ''new unit set-aside'' established for qualifying units in each state and, if areas of Indian country exist within the state's borders, a separate ''Indian country new unit set-aside'' for qualifying units in such Indian country. In this rulemaking, EPA is proposing revisions to each step of the three-step allocation process to better address units in Indian country and to better coordinate the unit-level allocation process with the proposed dynamic budget-setting process.

The EPA hosted an environmental justice webinar on October 26, 2021, that was attended by state regulatory authorities, environmental groups, federally recognized tribes, and small business stakeholders. The EPA will also continue to consult with the government of the Ute Indian Tribe of the Uintah and Ouray Reservation and plans to further consult with any other tribal officials under the EPA Policy on Consultation and Coordination with Indian Tribes early in the process of developing this proposed regulation to solicit meaningful and timely input into its development. The EPA plans to issue tribal consultation letters addressed to 574 tribes in February 2022 after the proposed rule is signed. The EPA will likely facilitate an additional tribal consultation through a webinar before finalizing this proposed rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because it implements a previously promulgated health-based federal standard. This action's health and risk assessments are contained in Chapter 5 of this RIA. The EPA believes that the ozone-related benefits, $PM_{2.5}$-related benefits, and CO_2-related benefits from this proposed rule will further improve children's health. Additionally, the ozone exposure analysis in Chapter 7 of the RIA suggests that nationally, children (ages 0–17) will experience at least as great a reduction in ozone exposures as adults (ages 18–64) in 2023 and 2026 under all regulatory alternatives of this proposed rulemaking.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. EPA has prepared a Statement of Energy Effects for the proposed regulatory contro*l* alternative as follows. The Agency estimates a 1 percent change in retail electricity prices on average across the contiguous U.S. in 2025, a 7.8 percent reduction in coal-fired electricity generation, a 0.15 percent increase in natural gas-fired electricity generation, and a 3.8 percent increase in renewable electricity generation in 2025 as a result of this proposed rule. EPA projects that utility power sector delivered natural gas prices will change by less than 1 percent in 2025. Details of the estimated energy effects are presented in Chapter 4 of the RIA, which is in the public docket.

I. National Technology Transfer and Advancement Act (NTTAA)

This proposed rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes that this action does not have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples, as specified in Executive Order 12898.[349] The documentation for this decision is contained in Section VIII. *Environmental Justice Analytical Considerations and Stakeholder Outreach and Engagement* of this Proposed rule and in Chapter 7, *Environmental Justice Impacts* of the RIA, which is in the public document. The RIA was prepared under E.O. 12866 *Regulatory Planning and Review* for this proposed rule. While the ozone exposure assessment was subject to several limitations, also described in Chapter 7 of the RIA, overall, ozone concentrations under the proposal, more stringent, and less stringent alternatives are predicted to impact demographic groups very similarly in both future years and across both EGUs and non-EGUs.

Therefore, regarding ozone concentrations, EPA does not find evidence of meaningful environmental justice concerns associated with ozone concentrations after imposition of the proposed regulatory action or alternatives under consideration. We also do not find evidence that any potential environmental justice concerns related to ozone would be meaningfully exacerbated in the regulatory alternatives under consideration, compared to the baseline. Importantly, the action described in this proposed rule is expected to lower ozone in many areas, including residual ozone nonattainment areas, and thus mitigate some pre-existing health risks of ozone across all populations evaluated.

In addition, the EPA provided the public, including those communities disproportionately impacted by the burdens of pollution, opportunities for meaningful engagement with the EPA on this action. A summary of outreach activities conducted by the Agency and what was heard from communities is provided in section VIII of this proposed rule.

K. Determinations Under CAA Section 307(b)(1) and (d)

Section 307(b)(1) of the CAA governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the United States Court of Appeals for the District of Columbia Circuit: (i) When the agency action consists of "nationally applicable regulations promulgated, or final action taken, by the Administrator," or (ii) when such action is locally or regionally applicable, but "such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination." For locally or regionally applicable final actions, the CAA reserves to EPA complete discretion whether to invoke the exception in (ii).

This proposed action, if finalized, would be "nationally applicable" within the meaning of CAA section 307(b)(1). In the alternative, to the extent a court finds this action to be locally or regionally applicable, the Administrator proposes to exercise the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of "nationwide scope or effect" within the meaning of CAA section 307(b)(1).[350]

This proposed action, if finalized, will implement the good neighbor provision in 26 states, spanning 8 EPA regions and 10 federal judicial circuits. The proposed action applies a uniform, nationwide analytical method and interpretation of CAA section 110(a)(2)(D)(i)(I) across these states, and the proposed rule is based on a common core of legal, technical, and policy determinations (as explained in further detail in the following paragraph). For these reasons, this proposed action is nationally applicable.

Alternatively, for these same reasons, the Administrator is exercising the discretion afforded to him by the CAA and hereby finds that this proposed action is based on multiple determinations of nationwide scope or effect for purposes of CAA section 307(b)(1).[351] Specifically, the proposed rule is based on a common core of statutory and case law analysis, factual findings, and policy determinations concerning the transport of ozone-precursor pollutants from the different states subject to it, as well as the impacts of those pollutants and the impacts of options to address those pollutants in yet other states. In this proposed action, EPA is applying its 4-step analytic framework to implement the good neighbor provision across these states, using a consistent set of policy and analytical determinations. The proposed determinations include a nationally consistent definition of receptors at Step 1 and findings identifying downwind nonattainment and maintenance receptors; the application of a nationally consistent contribution threshold at Step 2 to determine which states are linked to those receptors and should be further evaluated at Step 3; the use of a nationally consistent multi-factor test at Step 3 to determine which upwind-state contributions to nonattainment and maintenance receptors are "significant" and must be eliminated; and the proposed implementation at Step 4 of a nationally consistent set of emissions control strategies through emissions budgets and an integrated interstate emissions trading program for EGUs, a nationally consistent set of other compliance requirements for EGUs, and a nationally consistent set of enforceable emissions limits and associated compliance requirements for certain non-EGU sources in several industrial sectors across 23 states. Finally, the technical, scientific, and engineering information in support of these proposed determinations relies on a nationally consistent set of air quality modeling analyses and other nationally consistent analytical methods, as set forth elsewhere in this proposed rule and in the relevant supporting documents in the docket for this proposed rule.

Therefore, pursuant to CAA section 307(b), any petitions for review of this action, if and when it is finalized, must be filed in the D.C. Circuit within 60 days from the date such final action is published in the **Federal Register**.

This action is subject to the provisions of section 307(d). CAA section 307(d)(1)(B) provides that section 307(d) applies to, among other things, "the promulgation or revision of an implementation plan by the Administrator under [CAA section 110(c)]." 42 U.S.C. 7407(d)(1)(B). This action, among other things, proposes new federal implementation plans pursuant to the authority of section 110(c). To the extent any portion of this rulemaking, if finalized, is not expressly identified under section 307(d)(1)(B),

[349] 59 FR 7629, February 16, 1994.

[350] In proposing to invoke the exception by making and publishing a finding that this final action is based on a determination of nationwide scope or effect, the Administrator is taking into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

[351] In the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that the "nationwide scope or effect" exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. *See* H.R. Rep. No. 95–294 at 323, 324, reprinted in 1977 U.S.C.C.A.N. 1402–03.

the Administrator determines that the provisions of section 307(d) apply to such final action. *See* CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to ''such other actions as the Administrator may determine'').

List of Subjects

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 75

Environmental protection, Administrative practice and procedure, Air pollution control, Continuous emission monitoring, Electric power plants, Incorporation by reference, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 78

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Michael Regan,

Administrator.

For the reasons stated in the preamble, parts 52, 75, 78, and 97 of title 40 of the Code of Federal Regulations are proposed to be amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 52.38 by:

■ a. In paragraph (a)(1), removing ''(NO_X), except'' and adding in its place ''(NO_X) for sources meeting the applicability criteria set forth in that subpart, except'';

■ b. In paragraph (a)(4) introductory text, removing ''State's sources, and'' and adding in its place ''State, and'';

■ c. In table 1 to paragraph (a)(4)(i)(B), revising the entry for ''2025 and any year thereafter'';

■ d. In paragraph (a)(5) introductory text, removing ''State (but not sources in any Indian country within the borders of the State), regulations'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations'';

■ e. In table 2 to paragraph (a)(5)(i)(B), revising the entry for ''2025 and any year thereafter'';

■ f. In paragraph (a)(5)(iv), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ g. In paragraph (a)(5)(v), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';

■ h. Revising paragraphs (a)(6) and (a)(7)(ii);

■ i. In paragraph (a)(8)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';

■ j. In paragraph (b)(1), removing ''year), except'' and adding in its place ''year) for sources meeting the applicability criteria set forth in those subparts, except'';

■ k. Redesignating paragraphs (b)(2)(i) and (ii)as paragraphs (b)(2)(i)(A) and (B), respectively, redesignating paragraphs (b)(2)(iii) and (iv) as paragraphs (b)(2)(ii)(A) and (B), respectively, and redesignating paragraph (b)(2)(v) as paragraph (b)(2)(iii)(A);

■ l. In newly redesignated paragraph (b)(2)(ii)(A), removing ''Alabama, Arkansas, Iowa, Kansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.'' and adding in its place ''Iowa and Kansas.'';

■ m. Adding paragraphs (b)(2)(ii)(C) and (b)(2)(iii)(B) and (C);

■ n. In paragraph (b)(3) introductory text, removing ''or (ii)'';

■ o. Revising paragraph (b)(4) introductory text;

■ p. In table 3 to paragraph (b)(4)(ii)(B), revising the entry for ''2025 and any year thereafter'';

■ q. Revising paragraph (b)(5) introductory text;

■ r. In table 4 to paragraph (b)(5)(ii)(B), revising the entry for ''2025 and any year thereafter'';

■ s. In paragraph (b)(5)(v), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ t. In paragraph (b)(5)(vi), removing ''Indian country within the borders of the State, the'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority, the'';

■ u. In paragraph (b)(7) introductory text, removing ''(b)(2)(iii) or (iv)'' and adding in its place ''(b)(2)(ii)'';

■ v. Revising paragraph (b)(8) introductory text;

■ w. In paragraph (b)(8)(i), adding ''and'' after the semicolon;

■ x. Removing and reserving paragraph (b)(8)(ii);

■ y. Revising paragraph (b)(8)(iii)(A);

■ z. In table 5 to paragraph (b)(8)(iii)(B), revising the entry for ''2025 and any year thereafter'';

■ aa. In paragraph (b)(8)(iv), removing ''(b)(8)(i), (ii), or (iii)'' and adding in its place ''(b)(8)(i) or (iii)'' each time it appears;

■ bb. Revising paragraph (b)(9) introductory text;

■ cc. Removing and reserving paragraph (b)(9)(ii);

■ dd. Revising paragraph (b)(9)(iii)(A);

■ ee. In table 6 to paragraph (b)(9)(iii)(B), revising the entry for ''2025 and any year thereafter'';

■ ff. In paragraph (b)(9)(vi), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';

■ gg. Revising paragraph (b)(9)(vii);

■ hh. In paragraph (b)(9)(viii), removing ''(b)(9)(i), (ii), or (iii)'' and adding in its place ''(b)(9)(i) or (iii)'';

■ ii. Revising paragraphs (b)(10) introductory text, (b)(10)(i) and (ii), (b)(10)(v)(A) and (B), (b)(11) introductory text, (b)(11)(iii) introductory text, (b)(11)(iii)(A) introductory text, and (b)(11)(iii)(B);

■ jj. Removing and reserving paragraph (b)(11)(iii)(C);

■ kk. Revising paragraph (b)(11)(iii)(D);

■ ll. In paragraph (b)(11)(iv), removing ''paragraphs (b)(11)(iii)(B) and (C)'' and adding in its place ''paragraph (b)(11)(iii)(B)'';

■ mm. Revising paragraphs (b)(12) introductory text, (b)(12)(iii) introductory text, (b)(12)(iii)(A) introductory text, and (b)(12)(iii)(B);

■ nn. Removing and reserving paragraph (b)(12)(iii)(C);

■ oo. Revising paragraphs (b)(12)(iii)(D) and (b)(12)(vi) and (vii);

■ pp. In paragraph (b)(12)(viii), removing ''paragraphs (b)(12)(iii)(B) and (C)'' and adding in its place ''paragraph (b)(12)(iii)(B)'';

■ qq. Revising paragraphs (b)(13) introductory text and (b)(13)(i);
■ rr. In paragraph (b)(13)(ii), removing ''(b)(9)(ii) or'';
■ ss. In paragraph (b)(14)(i)(F), removing ''§ 97.825(b)'' and adding in its place ''§§ 97.806(c)(2) and (3) and 97.825(b)'';
■ tt. In paragraph (b)(14)(i)(G), removing ''§ 97.826(e)'' and adding in its place ''§ 97.826(f)'';
■ uu. Revising paragraphs (b)(14)(ii) and (b)(14)(iii) introductory text;
■ vv. In paragraph (b)(14)(iii)(D), removing ''and'' after the semicolon;
■ ww. In paragraph (b)(14)(iii)(E), removing ''(b)(2)(iv) of this section).'' and adding in its place ''(b)(2)(ii)(B) of this section);'';
■ xx. Adding paragraphs (b)(14)(iii)(F) and (G);
■ yy. In paragraph (b)(15)(iii), removing ''State (but not sources in any Indian country within the borders of the State):'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority:'';
■ zz. In paragraph (b)(16)(i)(B), removing ''§ 97.804(a) and (b) or'';
■ aaa. Revising paragraph (b)(16)(i)(C);
■ bbb. Redesignating paragraph (b)(16)(ii) as paragraph (b)(16)(ii)(A), and in the newly redesignated paragraph, removing ''(b)(2)(iv)'' and adding in its place ''(b)(2)(ii)(B)'';
■ ccc. Adding paragraph (b)(16)(ii)(B); and
■ ddd. Revising paragraphs (b)(17)(i) through (iii).

The revisions and additions read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of nitrogen oxides?

(a) * * *

(4) * * *

(i) * * *

(B) * * *

TABLE 1 TO PARAGRAPH (a)(4)(i)(B)

Year of the control period for which CSAPR NO_X annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * * * * *	
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(5) * * *

(i) * * *

(B) * * *

TABLE 2 TO PARAGRAPH (a)(5)(i)(B)

Year of the control period for which CSAPR NO_X annual allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * * * * * *	
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(6) *Withdrawal of CSAPR FIP provisions relating to NO_X annual emissions.* Except as provided in paragraph (a)(7) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a)(1), (a)(2)(i), and (a)(3) and (4) of this section for sources in the State and Indian country within the borders of the State, the provisions of paragraph (a)(2)(i) of this section will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(7) * * *

(ii) Notwithstanding the provisions of paragraph (a)(6) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Annual allowances under subpart AAAAA of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(C) The provisions of subpart EEEEE of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2017 through 2022 only, except as provided in paragraph (b)(14)(iii) of this section: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.

(iii) * * *

(B) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring in 2023 and each subsequent year: Alabama, Arkansas, Mississippi, Missouri, Oklahoma, Tennessee, Texas, and Wisconsin.

(C) The provisions of subpart GGGGG of part 97 of this chapter apply to sources in each of the following States and Indian country located within the borders of such States with regard to emissions occurring on and after [EFFECTIVE DATE OF FINAL RULE] and in each subsequent year: Delaware, Minnesota, Nevada, Utah, and Wyoming.

* * * * *

(4) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO_X Ozone Season Group 1 Trading Program.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart BBBBB of part 97 of this chapter for the State, and not substantively replacing any other provisions, as follows:

* * * * *

(ii) * * *

(B) * * *

TABLE 3 TO PARAGRAPH (b)(4)(ii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(5) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 1 Trading Programs.* A State listed in paragraph (b)(2)(i)(A) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 1 Trading Program set forth in §§ 97.502 through 97.535 of this chapter, except that the SIP revision:

* * * * *

(ii) * * *

(B) * * *

TABLE 4 TO PARAGRAPH (b)(5)(ii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(8) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO_X Ozone Season Group 2 Trading Program.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart EEEEE of part 97 of this chapter for the State, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under §§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 5 TO PARAGRAPH (b)(8)(iii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(9) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 2 Trading Programs.* A State listed in paragraph (b)(2)(ii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 2 Trading Program set forth in §§ 97.802 through 97.835 of this chapter, except that the SIP revision:

* * * * *

(iii) * * *

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 2 allowances for any such control period not exceeding the amount, under

§§ 97.810(a) and 97.821 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 2 trading budget minus the sum of the Indian country new unit set-aside and the amount of any CSAPR NO_X Ozone Season Group 2 allowances already allocated and recorded by the Administrator;

(B) * * *

TABLE 6 TO PARAGRAPH (b)(9)(iii)(B)

Year of the control period for which CSAPR NO_X ozone season Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(vii) Provided that, if and when any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority, the Administrator may modify his or her approval of the SIP revision to exclude the provisions in §§ 97.802 (definitions of ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.806(c)(2), and 97.825 of this chapter and the portions of other provisions of subpart EEEEE of part 97 of this chapter referencing these sections and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

* * * * *

(10) *State-determined allocations of CSAPR NO_X Ozone Season Group 3 allowances for 2024.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as CSAPR NO_X Ozone Season Group 3 allowance allocation provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2024, a list of CSAPR NO_X Ozone Season Group 3 units and the amount of CSAPR NO_X Ozone Season Group 3 allowances allocated to each unit on such list, provided that the list of units and allocations meets the following requirements:

(i) All of the units on the list must be units that are in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and that commenced commercial operation before January 1, 2021;

(ii) The total amount of CSAPR NO_X Ozone Season Group 3 allowance allocations on the list must not exceed the amount, under § 97.1010 of this chapter for the State and the control period in 2024, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the new unit set-aside and Indian country existing unit set-aside;

* * * * *

(v) * * *

(A) By [EFFECTIVE DATE OF FINAL RULE], the State must notify the Administrator electronically in a format specified by the Administrator of the State's intent to submit to the Administrator a complete SIP revision meeting the requirements of paragraphs (b)(10)(i) through (iv) of this section by September 1, 2023; and

(B) The State must submit to the Administrator a complete SIP revision described in paragraph (b)(10)(v)(A) of this section by September 1, 2023.

(11) *Abbreviated SIP revisions replacing certain provisions of the federal CSAPR NO_X Ozone Season Group 3 Trading Program.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, regulations replacing specified provisions of subpart GGGGG of part 97 of this chapter for the State, and not substantively replacing any other provisions, as follows:

* * * * *

(iii) The State may adopt, as CSAPR NO_X Ozone Season Group 3 allowance allocation or auction provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2025 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 3 allowances and may adopt, in addition to the definitions in § 97.1002 of this chapter, one or more definitions that shall apply only to terms as used in the adopted CSAPR NO_X Ozone Season Group 3 allowance allocation or auction provisions, if such methodology—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the new unit set-aside, the Indian country existing unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator, plus, if the State adopts regulations expanding applicability to additional units pursuant to paragraph (b)(11)(ii) of this section, an additional amount of CSAPR NO_X Ozone Season Group 3 allowances not exceeding the lesser of:

* * * * *

(B) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 3 allowances for any such control period to any CSAPR NO_X Ozone Season Group 3 units covered by § 97.1011(a)(1) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 3 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by June 1 of the year before the year of such control period; and

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(11)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter;

* * * * *

(12) *Full SIP revisions adopting State CSAPR NO_X Ozone Season Group 3 Trading Programs.* A State listed in paragraph (b)(2)(iii) of this section may adopt and include in a SIP revision, and the Administrator will approve, as correcting the deficiency in the SIP that is the basis for the CSAPR Federal

Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations that are substantively identical to the provisions of the CSAPR NO_X Ozone Season Group 3 Trading Program set forth in §§ 97.1002 through 97.1035 of this chapter, except that the SIP revision:

* * * * *

(iii) May adopt, as CSAPR NO_X Ozone Season Group 3 allowance allocation provisions replacing the provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2025 or any subsequent year, any methodology under which the State or the permitting authority allocates or auctions CSAPR NO_X Ozone Season Group 3 allowances and that—

(A) Requires the State or the permitting authority to allocate and, if applicable, auction a total amount of CSAPR NO_X Ozone Season Group 3 allowances for any such control period not exceeding the amount, under §§ 97.1010 and 97.1021 of this chapter for the State and such control period, of the CSAPR NO_X Ozone Season Group 3 trading budget minus the sum of the new unit set-aside, the Indian country existing unit set-aside, and the amount of any CSAPR NO_X Ozone Season Group 3 allowances already allocated and recorded by the Administrator, plus, if the State adopts regulations expanding applicability to additional units pursuant to paragraph (b)(12)(ii) of this section, an additional amount of CSAPR NO_X Ozone Season Group 3 allowances not exceeding the lesser of:

* * * * *

(B) Requires, to the extent the State adopts provisions for allocations or auctions of CSAPR NO_X Ozone Season Group 3 allowances for any such control period to any CSAPR NO_X Ozone Season Group 3 units covered by § 97.1011(a)(1) of this chapter, that the State or the permitting authority submit such allocations or the results of such auctions for such control period (except allocations or results of auctions to such units of CSAPR NO_X Ozone Season Group 3 allowances remaining in a set-aside after completion of the allocations or auctions for which the set-aside was created) to the Administrator by June 1 of the year before the year of such control period; and

* * * * *

(D) Does not provide for any change, after the submission deadlines in paragraph (b)(12)(iii)(B) of this section, in the allocations submitted to the Administrator by such deadlines and does not provide for any change in any allocation determined and recorded by the Administrator under subpart GGGGG of part 97 of this chapter or § 97.526(d) or § 97.826(d) or (e) of this chapter;

* * * * *

(vi) Must not include any of the requirements imposed on any unit in areas of Indian country within the borders of the State not subject to the State's SIP authority in the provisions in §§ 97.1002 through 97.1035 of this chapter and must not include the provisions in §§ 97.1011(a)(2), 97.1012, and 97.1021(g) through (j) of this chapter, all of which provisions will continue to apply under the portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision;

(vii) Provided that, if any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority before the Administrator's approval of the SIP revision, the SIP revision must exclude the provisions in §§ 97.1002 (definitions of ''base CSAPR NO_X Ozone Season Group 3 source'', ''base CSAPR NO_X Ozone Season Group 3 unit'', ''common designated representative'', ''common designated representative's assurance level'', and ''common designated representative's share''), 97.1006(c)(2), and 97.1025 of this chapter and the portions of other provisions of subpart GGGGG of part 97 of this chapter referencing these sections, and further provided that, if and when any covered unit is located in areas of Indian country within the borders of the State not subject to the State's SIP authority after the Administrator's approval of the SIP revision, the Administrator may modify his or her approval of the SIP revision to exclude these provisions and may modify any portion of the CSAPR Federal Implementation Plan that is not replaced by the SIP revision to include these provisions; and

* * * * *

(13) *Withdrawal of CSAPR FIP provisions relating to NO_X ozone season emissions; satisfaction of NO_X SIP Call requirements.* Following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(i), and (b)(3) and (4) of this section, paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section, or paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section for sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority—

(i) Except as provided in paragraph (b)(14) of this section, the provisions of paragraph (b)(2)(i), (ii), or (iii) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision; and

* * * * *

(14) * * *

(ii) Notwithstanding the provisions of paragraph (b)(13)(i) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 1 allowances under subpart BBBBB of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 2 allowances under subpart EEEEE of part 97 of this chapter, or allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(iii) Notwithstanding any discontinuation of the applicability of subpart BBBBB or EEEEE of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period pursuant to paragraph (b)(2)(i)(B), (b)(2)(ii)(B) or (C), or (b)(13)(i) of this section, the following provisions shall continue to apply with regard to all CSAPR NO_X Ozone Season Group 1 allowances and CSAPR NO_X Ozone Season Group 2 allowances at any time allocated for any control period to any source or other entity in the State and shall apply to all entities, wherever located, that at any time held or hold such allowances:

* * * * *

(F) The provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances); and

(G) The provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods after 2022 and recorded in the compliance accounts of sources in States listed in paragraph (b)(2)(ii)(C) of this section).

* * * * *

(16) * * *

(i) * * *

(C) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(9) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(ii), and (b)(7) and (8) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: Alabama, Indiana, and Missouri.

(ii) * * *

(B) Notwithstanding any provision of subpart EEEEE of part 97 of this chapter or any State's SIP, with regard to any State listed in paragraph (b)(2)(ii)(C) of this section and any control period that begins after December 31, 2022, the Administrator will not carry out any of the functions set forth for the Administrator in subpart EEEEE of part 97 of this chapter, except §§ 97.811(e) and 97.826(c) and (e) of this chapter, or in any emissions trading program provisions in a State's SIP approved under paragraph (b)(8) or (9) of this section.

(17) * * *

(i) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(10) of this section as replacing the CSAPR NO_X Ozone Season Group 3 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2024: [none].

(ii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(11) of this section as replacing the CSAPR NO_X Ozone Season Group 3 applicability provisions in § 97.1004(a) and (b) or § 97.1004(a)(1) and (2) of this chapter or the CSAPR NO_X Ozone Season Group 2 allowance allocation provisions in § 97.1011(a)(1) of this chapter with regard to the State and the control period in 2025 or any subsequent year: [none].

(iii) For each of the following States, the Administrator has approved a SIP revision under paragraph (b)(12) of this section as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (b)(1), (b)(2)(iii), and (b)(10) and (11) of this section with regard to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority: [none].

■ 3. Amend § 52.39 by:

■ a. In paragraph (a), removing "(SO_2), except" and adding in its place "(SO_2) for sources meeting the applicability criteria set forth in those subparts, except";

■ b. In paragraph (e) introductory text, removing "State's sources, and" and adding in its place "State, and";

■ c. In table 1 to paragraph (e)(1)(ii), revising the entry for "2025 and any year thereafter";

■ d. In paragraph (f) introductory text, removing "State (but not sources in any Indian country within the borders of the State), regulations" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations";

■ e. In table 2 to paragraph (f)(1)(ii), revising the entry for "2025 and any year thereafter";

■ f. In paragraph (f)(4), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority";

■ g. In paragraph (f)(5), removing "Indian country within the borders of the State, the" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority, the";

■ h. In paragraph (h) introductory text, removing "State's sources, and" and adding in its place "State, and";

■ i. In table 3 to paragraph (h)(1)(ii), revising the entry for "2025 and any year thereafter";

■ j. In paragraph (i) introductory text, removing "State (but not sources in any Indian country within the borders of the State), regulations" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, regulations";

■ k. In table 4 to paragraph (i)(1)(ii), revising the entry for "2025 and any year thereafter";

■ l. In paragraph (i)(4), removing "Indian country within the borders of the State" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority";

■ m. In paragraph (i)(5), removing "Indian country within the borders of the State, the" and adding in its place "areas of Indian country within the borders of the State not subject to the State's SIP authority, the";

■ n. Revising paragraphs (j) and (k)(2); and

■ o. In paragraphs (l)(3) and (m)(3), removing "State (but not sources in any Indian country within the borders of the State):" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority:".

The revisions read as follows:

§ 52.39 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of sulfur dioxide?

* * * * *

(e) * * *

(1) * * *

(ii) * * *

TABLE 1 TO PARAGRAPH (e)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(f) * * *

(i) * * *

(ii) * * *

TABLE 2 TO PARAGRAPH (f)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 1 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(h) * * *

(1) * * *

(ii) * * *

TABLE 3 TO PARAGRAPH (h)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(i) * * *

(1) * * *

(ii) * * *

TABLE 4 TO PARAGRAPH (i)(1)(ii)

Year of the control period for which CSAPR SO_2 Group 2 allowances are allocated or auctioned	Deadline for submission of allocations or auction results to the Administrator
* * *	* * * *
2025 and any year thereafter	June 1 of the year before the year of the control period.

* * * * *

(j) *Withdrawal of CSAPR FIP provisions relating to SO_2 emissions.* Except as provided in paragraph (k) of this section, following promulgation of an approval by the Administrator of a State's SIP revision as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan set forth in paragraphs (a), (b), (d), and (e) of this section or paragraphs (a), (c)(1), (g), and (h) of this section for sources in the State and Indian country within the borders of the State, the provisions of paragraph (b) or (c)(1) of this section, as applicable, will no longer apply to sources in the State and areas of Indian country within the borders of the State subject to the State's SIP authority, unless the Administrator's approval of the SIP revision is partial or conditional, and will continue to apply to sources in areas of Indian country within the borders of the State not subject to the State's SIP authority, provided that if the CSAPR Federal Implementation Plan was promulgated as a partial rather than full remedy for an obligation of the State to address interstate air pollution, the SIP revision likewise will constitute a partial rather than full remedy for the State's obligation unless provided otherwise in the Administrator's approval of the SIP revision.

(k) * * *

(2) Notwithstanding the provisions of paragraph (j) of this section, if, at the time of any approval of a State's SIP revision under this section, the Administrator has already started recording any allocations of CSAPR SO_2 Group 1 allowances under subpart CCCCC of part 97 of this chapter, or allocations of CSAPR SO_2 Group 2 allowances under subpart DDDDD of part 97 of this chapter, to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

■ 4. Add §§ 52.40 through 52.45 to read as follows:

* * * * *

Sec.

* * * * *

§ 52.40 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from sources not subject to the CSAPR ozone season trading program?

(a) *NO_X ozone season emissions.* This section establishes Federal Implementation Plan requirements for new and existing units in the industries specified in paragraph (b) of this section to eliminate significant contribution to nonattainment, or interference with maintenance, of the 2015 8-hour ozone National Ambient Air Quality Standards in other states pursuant to 42 U.S.C. 7410(a)(2)(D)(i)(I).

(b) *General requirements* (1) The NO_X emissions limitations and associated compliance requirements for the following listed source categories not subject to the CSAPR ozone season trading program constitute the Federal Implementation Plan provisions that relate to emissions of NO_X during the ozone season (defined as May 1 through September 30 of a calendar year): § 52.41 for engines in the Pipeline Transportation of Natural Gas Industry, § 52.42 for kilns in the Cement and Concrete Product Manufacturing Industry, § 52.43 for units in the Iron and Steel Mills and Ferroalloy Manufacturing Industry, § 52.44 for units in the Glass and Glass Product Manufacturing Industry, § 52.45 for boilers in Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills.

(2) The provisions of §§ 52.41 through 52.45 of this part apply to sources located in each of the following States, including Indian country located within the borders of such States, beginning in the 2026 ozone season and in each subsequent ozone season: Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, Wisconsin, and Wyoming.

(3) The owner or operator of an affected unit subject to the provisions of §§ 52.40 through 52.45 shall maintain files of all information (including all reports and notifications) required by these sections recorded in a form suitable and readily available for expeditious inspection and review. The files shall be retained for at least 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. At a minimum, the most recent 2 years of data shall be retained on site. The remaining 3 years of data may be retained off site. Such files may be maintained on microfilm, on a computer, on computer floppy disks, on magnetic tape disks, or on microfiche.

§ 52.41 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Pipeline Transportation of Natural Gas Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected unit means an engine meeting the applicability criteria of this section.

Four stroke means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

ISO conditions means 288 Kelvin (15 °C), 60 percent relative humidity and 101.3 kilopascals pressure.

Lean burn means any two-stroke or four-stroke spark ignited reciprocating internal combustion engine that does not meet the definition of a rich burn engine.

Nameplate rating means the manufacturer's design maximum capacity in horsepower (hp) at the installation site conditions. Starting from the completion of any physical change in the engine resulting in an increase in the maximum output (in hp) that the engine is capable of producing on a steady state basis and during continuous operation, such increased maximum output shall be as specified by the person conducting the physical change.

Natural gas means a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane) or non-hydrocarbons, composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. Natural gas does not include the following gaseous fuels: Landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable CO_2 content or heating value.

Natural gas-fired means that greater than or equal to 90% of the engine's heat input, excluding recirculated or recuperated exhaust heat, is derived from the combustion of natural gas.

Operator means any person who operates, controls, or supervises a natural gas-fired engine subject to this regulation and shall include, but not be limited to, any holding company, utility system, or plant manager of such natural gas-fired engine.

Owner means any holder of any portion of the legal or equitable title in a natural gas-fired engine subject to this regulation.

Pipeline transportation of natural gas means the movement of natural gas through an interconnected network of compressors and pipeline components, from field gathering networks near wellheads to end users, including:

(i) The compressor and pipeline network used for field gathering of natural gas from the wellheads for delivery to either processing facilities or connections to pipelines used for intrastate or interstate transportation of the natural gas; and

(ii) The compressor and pipeline network used to transport the natural gas from field gathering networks or processing facilities over a distance (intrastate or interstate) to and from storage facilities, to large natural gas end-users, and to distribution organizations that provide the natural gas to end-users.

Reciprocating internal combustion engine means a reciprocating engine in which power, produced by heat and/or pressure that is developed in the engine combustion chambers by the burning of a mixture of air and fuel, is subsequently converted to mechanical work.

Rich burn means any four-stroke spark ignited reciprocating internal combustion engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Internal combustion engines originally manufactured as rich burn engines but modified with passive emission control technology for nitrogen oxides (NO_X) (such as pre-combustion chambers) will be considered lean burn engines. Existing internal combustion engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered rich burn engines if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Spark ignition means a reciprocating internal combustion engine utilizing a spark plug (or other sparking device) to ignite the air/fuel mixture and with operating characteristics significantly similar to the theoretical Otto combustion cycle.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Two stroke means a type of reciprocating internal combustion engine which completes the power cycle in a single crankshaft revolution by combining the intake and compression operations into one stroke (one-half revolution) and the power and exhaust operations into a second stroke. This system requires auxiliary exhaust scavenging of the combustion products and inherently runs lean (excess of air) of stoichiometry.

(b) *Applicability.* You are subject to the requirements under this section if you own or operate a new or existing natural gas-fired spark ignition engine with a nameplate rating of 1,000 hp or greater that is used for pipeline transportation of natural gas and is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations.* Beginning with the 2026 ozone season and in each ozone season thereafter, the following emissions limitations must be met. Compliance with the numerical emissions limitations established in this section is based on the average of three 1-hour runs using the testing requirements and procedures in paragraph (d) of this section.

(1) If you own or operate a natural gas fired four stroke rich burn spark ignition engine with a nameplate rating of 1,000 hp or greater than you must meet a nitrogen oxides (NO_X) emissions limits of 1.0 grams per hp-hour (g/hp-hr).

(2) If you own or operate a natural gas fired four stroke lean burn spark ignition engine with a nameplate rating of 1,000 hp or greater than you must meet a NO_X emissions limits of 1.5 g/hp-hr.

(3) If you own or operate a natural gas fired two stroke lean spark ignition engine with a nameplate rating of 1,000 hp or greater than you must meet a NO_X emissions limits of 3.0 g/hp-hr.

(d) *Testing and monitoring requirements* (1) If you are an owner or operator of a natural gas fired spark ignition engine subject to a NO_X emissions limit under paragraph (b) of this section, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.

(2) Performance Testing Requirements:

(i) Engines that meet the certification requirements of § 60.4243(a) need not conduct any performance tests, consistent with the requirements of 40 CFR part 60, subpart JJJJ.

(ii) For non-certified engines, the following performance testing requirements apply:

(A) New engines must conduct an initial performance test within six months of engine startup and conduct subsequent performance testing every six months thereafter to demonstrate compliance.

(B) Existing engines must conduct an initial performance test within six months of becoming subject to an emissions limit under paragraph (b) of this section and conduct subsequent performance testing every six months thereafter to demonstrate compliance.

(iii) Performance tests must be conducted in accordance with the applicable reference test methods of 40 CFR part 60, appendix A, any alternative test method approved by EPA as of April 6, 2022 under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by EPA through notice-and-comment rulemaking.

(3) If a selective catalytic reduction (SCR) or non-selective catalytic reduction (NSCR) control device is used to reduce emissions:

(i) Monitor the inlet temperature to the catalyst daily and conduct maintenance if the temperature is not within the observed inlet temperature range from the most recent performance test or the temperatures specified by the manufacturer if no performance test was required by this section.

(ii) Measure the pressure drop across the catalyst monthly and conduct maintenance if the pressure drop is greater than 2 inches outside the baseline value established after each semiannual portable analyzer monitoring.

(iii) Engines that are subject to catalyst temperatures and catalyst pressure drop monitoring requirements under 40 CFR part 63, subpart ZZZZ must satisfy the requirements of § 52.41(d)(3).

(4) If you are not using a SCR or NSCR control device to reduce emissions are required to install a continuous parameter monitoring system (CPMS). You must install, operate, and maintain each CPMS according to the requirements in paragraphs (d)(4)(i) through (vi) of this section.

(i) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and quality assurance and quality control elements outlined in paragraphs (d)(4)(i)(A) through (E) of this section.

(A) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(B) Sampling interface (*e.g.,* thermocouple) location such that the monitoring system will provide representative measurements.

(C) Equipment performance evaluations, system accuracy audits, or other audit procedures.

(D) Ongoing operation and maintenance procedures in accordance with the requirements of paragraph (d)(1) of this section.

(E) Ongoing recordkeeping and reporting procedures in accordance with the requirements of paragraphs (e) and (f) of this section.

(ii) Install, operate, and maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(iii) The CPMS must collect data at least once every 15 minutes.

(iv) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(v) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(vi) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(e) *Recordkeeping requirements* (1) You must keep records of:

(i) Performance tests conducted pursuant to § 52.41(d)(2), including the date, engine settings on the date of the test, and documentation of the methods and results of the testing.

(ii) Catalyst monitoring required by § 52.41(d)(3), if applicable, and any actions taken to address monitored values outside the temperature or pressure drop parameters, including the date and a description of actions taken.

(iii) Parameters monitored pursuant to your site-specific monitoring plan for your CPMS.

(iv) Hours of operation on a daily basis.

(v) Tuning, adjustments, or other combustion process adjustments and the date of the adjustment(s).

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's Compliance and Emissions Data Reporting Interface (CEDRI) may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test following the procedures specified in paragraphs (f)(1)(i) through (iii):

(i) *Data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the extensible markup language (XML) schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *Confidential business information (CBI). Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraphs (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) If you are the owner or operator of an affected engine, you shall submit a semi-annual report, at least every six months, in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section. The report shall contain the following information:

(i) The name and address of the owner and operator;

(ii) The address of the subject engine;

(iii) Longitude and latitude coordinates of the subject engine;

(iv) Identification of the subject engine;

(v) Statement of compliance with the applicable emission limit under § 52.41(b);

(vi) Statement of compliance regarding the conduct of maintenance and operations in a manner consistent with good air pollution control practices for minimizing emissions;

(vii) The date and results of the performance test conducted pursuant to § 52.41(d);

(viii) If applicable, a statement documenting any change in the operating characteristics of the subject engine; and

(ix) A statement certifying that the information included in the semi-annual report is complete and accurate.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.42 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Cement and Concrete Product Manufacturing Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected unit means a cement kiln meeting the applicability criteria of this section.

Cement plant means any facility manufacturing cement by either the wet or dry process.

Clinker means the product of a cement kiln from which finished cement is manufactured by milling and grinding.

Cement kiln means an installation, including any associated pre-heater or pre-calciner devices, that produces clinker by heating limestone and other materials to produce Portland cement.

Operating day means a 24-hour period beginning at 12:00 midnight during which the kiln produces clinker at any time.

Rolling average means the weighted average of all data, meeting QA/QC requirements or otherwise normalized, collected during the applicable averaging period. The period of a rolling average stipulates the frequency of data averaging and reporting. To demonstrate compliance with an operating parameter a 30-day rolling average period requires calculation of a new average value each operating day and shall include the average of all the hourly averages of the specific operating parameter. For demonstration of compliance with an emissions limit based on pollutant concentration, a 30-day rolling average is comprised of the average of all the hourly average concentrations over the previous 30 operating days. For demonstration of compliance with an emissions limit based on lbs-pollutant per production unit, the 30-day rolling average is calculated by summing the hourly mass emissions over the previous 30 operating days, then dividing that sum by the total production during the same period.

(b) *Applicability.* You are subject to the requirements of this section if you own or operate a new or existing cement kiln that emits or has the potential to emit 100 tons per year or more of NO_X and is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) Emission limitations (1) If you own or operate a cement kiln under paragraph (b) of this section you are subject to the NO_X emissions limits in the following table and the NO_X source cap limit under paragraph (c)(2) of this section, beginning with the 2026 ozone season and in each ozone season thereafter.

TABLE 1 TO PARAGRAPH (c)(1)

Kiln type	Proposed NO_X emissions limit (lb/ton of clinker)
Long Wet	4.0
Long Dry	3.0
Preheater	3.8
Precalciner	2.3
Preheater/Precalciner	2.8

(2) The NO_X source cap limit is calculated in accordance with the following equation:

$$CAP2015\ Ozone\ Transport = \frac{(KW\ x\ NW) + (KD\ x\ ND)}{\left(2000\,\dfrac{pounds}{ton}\ x\ 365\,\dfrac{days}{year}\right)}$$

Where:

CAP2015 Ozone Transport = total allowable NO_X emissions from all cement kilns located at one cement plant, in tons per day, on a 30-operating day rolling average basis;

KD = 1.7 pounds NO_X per ton of clinker for dry preheater-precalciner or precalciner kilns;

KW = 3.4 pounds NO_X per ton of clinker for long wet kilns;

ND = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all dry preheater-precalciner or precalciner kilns located at one cement plant; and

NW = the average annual production in tons of clinker plus one standard deviation for the three most recent calendar years from all long wet kilns located at one cement plant.

(d) *Testing and monitoring requirements* (1) If you own or operate a cement manufacturing plant subject to the NO_X emissions limits under paragraph (c) of this section you must conduct performance tests, on a semi-annual basis, in accordance with the applicable reference test methods of 40 CFR part 60, Appendix A, any alternative test method approved by EPA as of April 6, 2022 under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by EPA through notice-and-comment rulemaking. You must calculate and record the 30-operating day rolling emission rate of NO_X as the total of all hourly emissions data for a cement kiln in the preceding 30 days, divided by the total tons of clinker produced in that kiln during the same 30-operating day period using Equation 6 of 40 CFR 60.64(c)(1), shown in this equation:

$$E_{30D} = k\left(\frac{\sum_{i=1}^{n} Ci\ Qi}{P}\right)$$

Where:
E_{30D} = 30 kiln operating day average emission rate of NO_X, in lbs/ton of clinker.
Ci = Concentration of NO_X for hour i, in ppm.
Qi = Volumetric flow rate of effluent gas for hour i, where Ci and Qi are on the same basis (either wet or dry), in scf/hr.
P = 30 days of clinker production during the same time period as the NO_X emissions measured, in tons.
k = Conversion factor, 1.194×10^{-7} for NO_X, in lb/scf/ppm.
n = Number of kiln operating hours over 30 kiln operating days.

(e) Recordkeeping requirements (1) If you own or operate a cement manufacturing plant subject to the NO_X emissions limits under paragraph (c) of this section you must retain records of the calculations and measurements as required in paragraph (d) of this section for the 5-year period specified in 52.40(b)(3).

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test following the procedures specified in paragraphs (f)(1)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii) of this section. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) If you are the owner or operator of an affected cement kiln, you shall submit a semi-annual, at least every six months, report in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.43 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Iron and Steel Mills and Ferroalloy Manufacturing Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected unit means any annealing furnace, basic oxygen process furnace, blast furnace, coke oven facility, electric arc furnace, ladle metallurgy furnace, ladle/tundish preheating system, reheat furnace, taconite production kiln, vacuum degasser, and industrial boiler meeting the applicability criteria of this section, and any such unit contained within a BOF Shop meeting the applicability criteria of this section.

Annealing furnace shall mean a furnace used to heat materials at very high temperatures to change their hardness and strength properties.

Basic Oxygen Process Furnace (BOF) shall mean a refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel. This definition includes both top and bottom blown furnaces, but does not include argon oxygen decarburization furnaces.

Blast furnace means refractory-lined furnaces charged through its top with iron ore pellets (taconite), sinter, flux (limestone and dolomite), and coke in a reducing atmosphere to produce iron.

BOF Shop means the place where steel making operations occur, beginning with the transfer of molten iron (hot metal) from the torpedo car and ending just prior to casting the molten steel, including hot metal transfer, desulfurization, slag skimming, refining in a basic oxygen process furnace, and ladle metallurgy.

BOF Baghouse System means the control system for control of emissions from charging and tapping of the BOFs, including the capture hoods, ductwork and the BOF Baghouse.

Coke means carbon product that is formed by the thermal distillation of coal at high temperatures in the absence of air in coke oven batteries.

Coke Ovens means ovens producing coke for use in blast furnaces.

Day means a calendar day unless expressly stated to be a business day. In computing any period of time for recordkeeping and reporting purposes where the last day would fall on a Saturday, Sunday, or Federal holiday, the period shall run until the close of business of the next business day.

Electric Arc Furnace means a furnace equipped with electrodes used to produce carbon steels and alloy steels primarily by recycling ferrous scrap.

Exceedance means a reading in excess of an applicable opacity or emissions limitation.

Ladle Metallurgy Furnace means a furnace used to refine molten steel into specialty grades while keeping the steel in the ladle.

Ladle/Tundish Preheaters means equipment used to preheat ladles or tundishes to minimize temperature drop prior to use in iron or molten steel refinement.

Reheat Furnace means a furnace used to heat steel product to temperatures at which it will be suitable for deformation and further processing.

Steel Production Cycle means the operations conducted within the basic oxygen process furnace shop that are required to produce each batch of steel, including scrap charging, preheating, hot metal charging, primary oxygen blowing, sampling, (vessel turndown and turnup), additional oxygen blowing, tapping, and deslagging. The steel production cycle begins when the scrap is charged to the furnace and ends three minutes after the slag is emptied from the vessel into the slag pot.

Taconite production kiln means a furnace designed to dry and indurate taconite concentrates to create taconite pellets.

Vacuum degasser means a unit operated within an iron and steel facility to expose molten steel at low pressure to remove certain gases during steel refinement.

(b) *Applicability* The requirements of this section apply to each new or existing emissions unit at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X, and to each BOF Shop containing two or more such units that collectively emit or have the potential to emit 100 tons per year or more of NO_X, and that is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emissions Limitations and Requirements.* Beginning with the 2026 ozone season and in each ozone season thereafter, the emissions limitations in the following table must be met on a 3-hour rolling average.

TABLE 1 TO PARAGRAPH (c)

Emission unit	NO_X Emissions standard or control requirement
Blast Furnace	0.03 lb/mmBtu.
Basic Oxygen Process Furnace	0.07 lb/ton steel.
Electric Arc Furnace	0.15 lb/ton steel.
Ladle/tundish Preheaters	0.06 lb/mmBtu.
Reheat furnace	0.05 lb/mmBtu.
Annealing Furnace	0.06 lb/mmBtu.
Vacuum Degasser	0.03 lb/mmBtu.
Ladle Metallurgy Furnace	0.1 lb/ton steel.
Taconite Production Kilns	Install and operate low NO_X burners as required by 2013 and 2016 Minnesota FIPs. 40 CFR § 52.1183.
Coke Ovens (charging)	0.15 lb/ton of coal charged.
Coke Oven push cars and pushing-charging machines (pushing)	0.015 lb/ton of coal pushed.

TABLE 1 TO PARAGRAPH (c)—Continued

Emission unit	NO_X Emissions standard or control requirement
Boilers—Coal, blast furnace gas, and coke oven gas	0.20 lb/mmBtu.
Boilers—Residual oil	0.20 lb/mmBtu.
Boilers—Distillate oil	0.12 lb/mmBtu.
Boilers—Natural gas	0.08 lb/mmBtu.

(d) *Compliance and Monitoring Requirements*—(1) *Compliance Requirements* (i) Each affected unit identified in Table 1 to paragraph (c) of this section must design, install, maintain, and continuously operate NO_X control devices as necessary to achieve emissions limits set forth in Table 1 to paragraph (c) of this section in a manner consistent with good air pollution control practices as described in 40 CFR 63.6(e).

(A) If you are the owner or operator of an affected unit not identified in paragraph (d)(1)(i)(B) of this section, you must submit to EPA a work plan for each affected unit within 180 days of the effective date of this rule identifying how each affected unit will comply with the emissions limits set forth in Table 1 to paragraph (c) of this section. Each work plan must include identification of the control device selected and the phased construction timeframe by which you will design, install, and consistently operate the device.

(B) For each taconite production kiln affected by this rule, you must install, maintain, and continuously operate low-NO_X burners to reduce existing average NO_X emissions from the facility by 40% during all periods of kiln operation.

(*1*) If you have already installed low-NO_X burners as required by the 2013 or 2016 Minnesota Regional Haze Federal Implementation Plans,[352] then you must submit a report to EPA within 180 days of the effective date of this rule demonstrating that the low-NO_X burner is designed to achieve 40% reduction of kiln NO_X emissions.

(*2*) If you have not yet installed low-NO_X burners as required by the 2013 or 2016 Minnesota Regional Haze Federal Implementation Plans, then you must submit a work plan identifying the low-NO_X burner selected and the phased construction timeframe by which you will design, install, and consistently operate the burner. Each work plan shall include performance test results obtained within five years of the effective date of this rule to be used as baseline emission testing data providing the basis for required emission reductions.

(2) *Monitoring Requirements* (i) For each unit identified in Table 1 to paragraph (c) of this section of this rule, you must install, operate, and maintain a NO_X continuous emission monitoring system (CEMS) to monitor compliance with the emissions limits set forth in Table 1 to paragraph (c) of this section. Each CEMS shall be installed and operated in accordance with requirements set forth at 40 CFR part 60, appendix B.

(ii) You must conduct a performance evaluation of each CEMS according to the requirements in 40 CFR 63.8 and according to 40 CFR part 60, appendix B.

(iii) You must notify EPA in writing of your intention to conduct a performance test at least 60 calendar days before the performance test is initially scheduled to begin in accordance with 40 CFR 63.7 (b).

(iv) As specified in 40 CFR 63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, each representing a different 15-minute period within the same hour, to have a valid hour of data.

(v) All CEMS data must be reduced as specified in 40 CFR 63.8(g)(2) and recorded as NO_X in parts per million by volume, dry basis (ppmvd).

(vi) Proper maintenance. You must maintain the CEMS equipment at all times that the unit is operating, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(vii) You must conduct all monitoring in continuous operation at all times that the unit is operating, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration drift checks and required zero and high-level adjustments). Quality assurance or control activities must be performed according to procedure 1 of 40 CFR part 60, appendix F.

(viii) Data recorded during monitoring malfunctions, associated repairs, out-of-control periods, and required quality assurance or control activities should not be used for purposes of calculating data averages. You must use all of the data collected from all other periods in assessing compliance. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring equipment to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system is out-of-control and data are not available for required calculations constitutes a deviation from the monitoring requirements.

(e) *Recordkeeping requirements* (1) You shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emission rates measured or predicted;

(iii) The 30-day average NO_X emission rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emission rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emission rates are in excess of the applicable NO_X emission limit in Table 1 to paragraph (c) of this section with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(viii) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ix) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B of 40 CFR part 60; and

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F.

[352] *https://archive.epa.gov/reg5oair/taconite/web/html/index.html.*

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 180 days of the effective date of this rule, you shall submit a work plan in accordance with requirements set forth in paragraph (d)(1)(i)(A) of this section, including identification of the control device selected and the phased construction timeframe by which you will design, install, and consistently operate the device. For taconite kilns subject to paragraph (d)(1)(i)(B)(2) of this section each work plan shall include performance test results obtained within five years of the effective date of this rule to be used as baseline emission testing data providing the basis for required emission reductions.

(2) By no later than March 30, 2026, each owner/operator of an affected unit shall submit a final report certifying installation of each selected control device has completed. Each such report shall contain dates of final construction and relevant performance testing, where applicable, demonstrating compliance with limits set forth in Table 1 to paragraph (c) of this section.

(3) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in paragraphs (c)(3)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(4) You are required to submit excess emission reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under paragraph (c)(3)(iii) of this section, that exceeds the applicable emission limit in paragraph (c) of this section. Excess emission reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(5) If you own or operate an affected unit subject to the continuous monitoring requirements for NO_X under paragraph (d) of this section, you shall submit reports containing the information recorded under paragraph (d) as described in paragraph (e)(6) of this section. Compliance reports for continuous monitoring must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(6) If you own or operate an affected unit, you must submit electronic quarterly reports no later than 30 days after the end of the calendar quarter. The reports shall be accompanied by a certification from the owner or operator indicating whether the affected unit was in compliance with the applicable emission limits and minimum data requirements of this section during the reporting period. These quarterly reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(7) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(7)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(8) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that

reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(8)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.44 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Glass and Glass Product Manufacturing Industry?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of part 60.

Affected units means a glass manufacturing furnace meeting the applicability criteria of this section.

All-electric melter means a glass melting furnace in which all the heat required for melting is provided by electric current from electrodes submerged in the molten glass, although some fossil fuel may be charged to the furnace as raw material only.

Borosilicate recipe means glass product composition of the following approximate ranges of weight proportions: 60 to 80 percent silicon dioxide, 4 to 10 percent total R_2O (*e.g.,* Na_2O and K_2O), 5 to 35 percent boric oxides, and 0 to 13 percent other oxides.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in Standard Industrial Classification 3221 (SIC 3221).

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or that is used as a raw material for nonexperimental furnaces.

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in SIC 3211.

Glass melting furnace means a unit comprising a refractory vessel in which raw materials are charged, melted at high temperature, refined, and conditioned to produce molten glass. The unit includes foundations, superstructure and retaining walls, raw material charger systems, heat exchangers, melter cooling system, exhaust system, refractory brick work, fuel supply and electrical boosting equipment, integral control systems and instrumentation, and appendages for conditioning and distributing molten glass to forming apparatuses. The forming apparatuses, including the float bath used in flat glass manufacturing and flow channels in wool fiberglass and textile fiberglass manufacturing, are not considered part of the glass melting furnace.

Glass produced means the weight of the glass pulled from the glass melting furnace.

Hand glass melting furnace means a glass melting furnace where the molten glass is removed from the furnace by a glassworker using a blowpipe or a pontil.

Lead recipe means glass product composition of the following ranges of weight proportions: 50 to 60 percent silicon dioxide, 18 to 35 percent lead oxides, 5 to 20 percent total R_2O (*e.g.,* Na_2O and K_2O), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), 0 to 15 percent total RO (*e.g.,* CaO, MgO), other than lead oxide, and 5 to 10 percent other oxides.

Pressed and blown glass means glass which is pressed, blown, or both, including textile fiberglass, noncontinuous flat glass, noncontainer glass, and other products listed in SIC 3229. It is separated into: Glass of borosilicate recipe, Glass of soda-lime and lead recipes, and Glass of opal, fluoride, and other recipes.

Raw material means minerals, such as silica sand, limestone, and dolomite; inorganic chemical compounds, such as soda ash (sodium carbonate), salt cake (sodium sulfate), and potash (potassium carbonate); metal oxides and other metal-based compounds, such as lead oxide, chromium oxide, and sodium antimonate; metal ores, such as chromite and pyrolusite; and other substances that are intentionally added to a glass manufacturing batch and melted in a glass melting furnace to produce glass. Metals that are naturally-occurring trace constituents or contaminants of other substances are not considered to be raw materials.

Rebricking means cold replacement of damaged or worn refractory parts of the glass melting furnace. Rebricking includes replacement of the refractories comprising the bottom, sidewalls, or roof of the melting vessel; replacement of refractory work in the heat exchanger; replacement of refractory portions of the glass conditioning and distribution system.

Soda-lime recipe means glass product composition of the following ranges of weight proportions: 60 to 75 percent silicon dioxide, 10 to 17 percent total R_2O (*e.g.,* Na_2O and K_2O), 8 to 20 percent total RO but not to include any PbO (*e.g.,* CaO, and MgO), 0 to 8 percent total R_2O_3 (*e.g.,* Al_2O_3), and 1 to 5 percent other oxides.

Textile fiberglass means fibrous glass in the form of continuous strands having uniform thickness.

Wool fiberglass means fibrous glass of random texture, including fiber glass insulation, and other products listed in SIC 3296.

(b) *Applicability* You are subject to the requirements under this section if you own or operate a new or existing glass manufacturing furnace that directly emits or has the potential to emit 100 tons per year or more of NO_X and is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emissions limitations* If you own or operate an affected unit you are subject to the NO_X emissions limits in the following table beginning with the 2026 ozone season and in each ozone season thereafter:

TABLE 1 TO PARAGRAPH (c)

Furnace type	Proposed NO_X emissions limit (lb/ton of glass produced)
Container Glass Manufacturing Furnace	4.0
Pressed/Blown Glass Manufacturing Furnace or Fiberglass Manufacturing Furnace	4.0
Flat Glass Manufacturing Furnace	9.2

(d) *Testing and Monitoring Requirements* If you own or operate an affected unit you must conduct performance tests, on a semiannual basis, in accordance with the applicable reference test methods of 40 CFR part 60, Appendix A, any alternative test method approved by EPA as of April 6, 2022 under 40 CFR 59.104(f), 60.8(b)(3), 61.13(h)(1)(ii), 63.7(e)(2)(ii), or 65.158(a)(2) and available at EPA's website (*https://www.epa.gov/emc/broadly-applicable-approved-alternative-test-methods*), or other methods and procedures approved by EPA through notice-and-comment rulemaking. Direct measurement or material balance using good engineering practice shall be used to determine the amount of glass pulled during the performance test. The rate of glass produced is defined as the weight of glass pulled from the affected facility during the performance test divided by the number of hours taken to perform the performance test.

(1) Owners or operators of affected units must calculate and record the 30-operating day rolling emission rate of NO_X as the total of all hourly emissions data for a glass manufacturing furnace in the preceding 30 days, divided by the total tons of glass produced in that furnace during the same 30-operating day period. If a continuous emission monitoring system has not been installed on the affected unit, the owner or operator shall conduct the following steps:

(A) *Step 1:* determine the average pounds of NO_X emitted per hour by averaging three one-hour tests,

(B) *Step 2:* determine the average tons of glass removed per hour during the same time period as the three one-hour tests in step 1,

(C) *Step 3:* divide the average pounds of NO_X emitted per hour determined in step 1 by the average tons of glass removed per hour determined in step 2,

(D) *Step 4:* compare the quotient to the emission limits specified at § 52.44(c)(1).

(2) If a continuous emission monitoring system has been installed on the affected unit, on a daily basis the owner or operator shall conduct the following steps:

(A) *Step 1:* determine the average pounds of NO_X emitted per day,

(B) *Step 2:* determine the tons of glass removed per day,

(C) *Step 3:* divide the average pounds of NO_X emitted per day determined in step (1) by the tons of glass removed per day determined in step (2). The quotient is pounds of NO_X emitted per ton of glass removed; and

(D) *Step 4:* compare the quotient to the emission limit specified at § 52.44(c)(1).

(e) *Recordkeeping requirements* (1) If you own or operate an affected unit, you must retain records of the calculations and measurements as required in paragraph (e) of this section for 5-year period specified in 52.40(b)(3). You must record the results of each inspection and maintenance proposed rule in a logbook (written or electronic format). You shall keep the logbook onsite and make the logbook available to the permitting authority upon request, consistent with the requirements of 40 CFR part 63, subpart SSSSSS, § 63.11457(c).

(2) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(f) *Reporting requirements* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test following the procedures specified in paragraphs (e)(1)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (f)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (f)(1)(i) and (ii). All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) If you own or operate an affected unit, you shall submit a semi-annual report, at least every six months, in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(3) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (f)(3)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(4) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (f)(4)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

§ 52.45 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from the Basic Chemical Manufacturing, Petroleum and Coal Products Manufacturing, and Pulp, Paper, and Paperboard Mills Industries?

(a) *Definitions.* All terms not defined herein shall have the meaning given them in the Act and in subpart A of 40 CFR part 60.

Affected unit means an industrial boiler meeting the applicability criteria of this section.

(b) *Applicability.* (1) The requirements of this section apply to each new or existing boiler with a design capacity of 100 mmBtu/hr or greater fueled by coal, residual oil, distillate oil, or natural gas, located at sources that are within the Basic Chemical Manufacturing industry (NAICS code 3251xx), the Petroleum and Coal Products Manufacturing industry (NAICS code 3241xx), and the Pulp, Paper, and Paperboard industry (NAICS code 3221xx), and which is located within any of the States listed in § 52.40(a)(1)(ii), including Indian country located within the borders of any such State(s).

(c) *Emission limitations.* Beginning with the 2026 ozone season and in each ozone season thereafter, the following emission limits apply, based on a 30-day averaging time:

(1) Coal-fired industrial boilers: 0.20 lbs NO_X/mmBtu;

(2) Residual oil-fired industrial boilers: 0.15 lbs NO_X/mmBtu;

(3) Distillate oil-fired industrial boilers: 0.12 lbs NO_X/mmBtu; and

(4) Natural gas-fired industrial boilers: 0.08 lbs NO_X/mmBtu.

(d) *Initial compliance testing.* (1) To determine compliance with the emission limits for NO_X identified in paragraph (c) of this section, you shall conduct an initial compliance test as described in 40 CFR § 60.8 using the continuous system for monitoring NO_X specified by EPA Test Method 7E—Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure), as described at 40 CFR part 60, Appendix A–4. In lieu of the timing of the compliance test described in 40 CFR 60.8(a), the test shall be conducted within 90 days from the installation of the pollution control equipment used to comply with the NO_X emission limits in paragraph (c) of this section.

(2) For the initial compliance test, NO_X emissions from the affected unit shall be monitored for 30 successive operating days and the 30-day average emission rate will be used to determine compliance with the NO_X emission limits in paragraph (c) of this section. The 30-day average emission rate is calculated as the average of all hourly emission data recorded by the monitoring system during the 30-day test period.

(e) *Monitoring requirements.* (1) The NO_X emission limits in paragraph (c) of this section shall apply at all times.

(2) You shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for measuring NO_X emissions and either oxygen (O_2) or carbon dioxide (CO_2), unless the Administrator has approved a request from the you to use an alternative monitoring technique under paragraph (e)(8) of this section. If you have previously installed a NO_X emission rate CEMS to meet the requirements of 40 CFR part 75 and continue to meet the ongoing requirements of 40 CFR part 75, that CEMS may be used to meet the monitoring requirements of this section.

(3) The CEMS required under paragraph (e)(2) of this section shall be operated and data recorded during all periods of operation of the affected unit except for CEMS breakdowns and repairs. Data shall be recorded during calibration checks and zero and span adjustments.

(4) The 1-hour average NO_X emission rates measured by the CEMS required by paragraph (e)(2) of this section shall be expressed in terms of lbs/mmBtu heat input and shall be used to calculate the average emission rates under 40 CFR 52.45(c).

(5) Following the date on which the initial compliance test is completed, you shall determine compliance with the applicable NO_X emission limit in paragraph (c) of this section on a continuous basis using a 30-day rolling

average emission rate unless the affected unit monitors emissions by means of an alternative monitoring procedure approved pursuant to paragraph (e)(8) of this section. A new 30-day rolling average emission rate is calculated for each operating day as the average of all the hourly NO_X emission data for the preceding 30 operating days.

(6) The procedures under 40 CFR 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems. Additionally, the span value for units combusting coal shall be 1,000 ppm NO_X, and for units combusting oil or gas the span value shall be 500 ppm NO_X. As an alternative to meeting the span value requirements stated above, you may elect to use the NO_X span values determined according to section 2.1.2 in appendix A to 40 CFR part 75.

(7) When NO_X emission data are not obtained because of CEMS breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using standby monitoring systems, Method 7 of 40 CFR part 60, Method 7A of 40 CFR part 60, or other approved reference methods to provide emission data for a minimum of 75 percent of the operating hours in each affected unit operating day, in at least 22 out of 30 successive operating days.

(8) Installation of a CEMS for NO_X may be delayed until after the initial performance test has been conducted. If you demonstrate during the performance test that emissions of NO_X are less than 70 percent of the applicable emission limit in paragraph (c) of this section, a CEMS for measuring NO_X emissions is not required. If you demonstrate its boiler emits less than 70 percent of the applicable emission limit chooses to not install a CEMS, you must submit a written request to the Administrator that documents the results of the initial performance test and includes an alternative monitoring procedure that will be used to track compliance with the applicable NO_X emission limit(s) in paragraph (c) of this section. The Administrator will consider the request and, following public notice and comment, may approve the alternative monitoring procedure with or without revision, or disapprove the request. Upon receipt of a disapproved request, you will have one year to install a CEMS in accordance with the provisions for CEMS described in paragraph (e) of this section.

(f) *Recordkeeping requirements* (1) You shall record and maintain records of the amounts of each fuel combusted during each calendar month.

(2) You shall maintain records of the following information for each day the affected unit operates:

(i) Calendar date;

(ii) The average hourly NO_X emission rates (expressed as lbs NO_2/mmBtu heat input) measured or predicted;

(iii) The 30-day average NO_X emission rates calculated at the end of each affected unit operating day from the measured or predicted hourly NO_X emission rates for the preceding 30 steam generating unit operating days;

(iv) Identification of the affected unit operating days when the calculated 30-day average NO_X emission rates are in excess of the applicable NO_X emission limit in paragraph (c) of this section with the reasons for such excess emissions as well as a description of corrective actions taken;

(v) Identification of the affected unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

(vi) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

(vii) Identification of ''F'' factor used for calculations, method of determination, and type of fuel combusted;

(viii) Identification of the times when the pollutant concentration exceeded full span of the CEMS;

(ix) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3 in appendix B of 40 CFR part 60; and

(x) Results of daily CEMS drift tests and quarterly accuracy assessments as required under Procedure 1 of 40 CFR part 60, appendix F.

(3) Any records required to be maintained by this section that are submitted electronically via the EPA's CEDRI may be maintained in electronic format. This ability to maintain electronic copies does not affect the requirement for facilities to make records, data, and reports available upon request to the EPA as part of an on-site compliance evaluation.

(g) *Reporting requirements.* (1) Within 60 days after the date of completing each performance test required by this section, you must submit the results of the performance test or performance evaluation of the CEMS following the procedures specified in paragraphs (g)(i) through (iii) of this section:

(i) *Data collected using test methods supported by the EPA's ERT as listed on the EPA's ERT website (https://www.epa.gov/electronic-reporting-air-emissions/electronic-reporting-tool-ert) at the time of the test.* Submit the results of the performance test to the EPA via the CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section, which can be accessed through the EPA's CDX (*https://cdx.epa.gov/*). The data must be submitted in a file format generated using the EPA's ERT. Alternatively, you may submit an electronic file consistent with the XML schema listed on the EPA's ERT website.

(ii) *Data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT website at the time of the test.* The results of the performance test must be included as an attachment in the ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the ERT generated package or alternative file to the EPA via CEDRI.

(iii) *CBI. Do not use CEDRI to submit information you claim as CBI.* Anything submitted using CEDRI cannot later be claimed CBI. Although we do not expect persons to assert a claim of CBI, if you wish to assert a CBI claim for some of the information submitted under paragraph (g)(1)(i) or (ii) of this section, you must submit a complete file, including information claimed to be CBI, to the EPA. The file must be generated using the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT website. Submit the file on a compact disc, flash drive, or other commonly used electronic storage medium and clearly mark the medium as CBI. Mail the electronic medium to U.S. EPA/OAQPS/CORE CBI Office, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described in paragraphs (g)(1)(i) and (ii) of this section. All CBI claims must be asserted at the time of submission. Furthermore, under CAA section 114(c), emissions data is not entitled to confidential treatment, and the EPA is required to make emissions data available to the public. Thus, emissions data will not be protected as CBI and will be made publicly available.

(2) You are required to submit excess emission reports for any excess emissions that occurred during the reporting period. Excess emissions are defined as any calculated 30-day rolling average NO_X emission rate, as determined under paragraph (g)(3)(iii) of this section, that exceeds the applicable emission limit in paragraph (c) of this section. Excess emission reports must be

submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(3) If you own or operate an affected unit subject to the continuous monitoring requirements for NO_X under paragraph (e) of this section, you shall submit reports containing the information recorded under paragraph (e) of this section as described in paragraph (g)(2) of this section. Compliance reports for continuous monitoring must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(4) If you own or operate an affected unit, you must submit electronic quarterly reports no later than 30 days after the end of the calendar quarter. The reports shall be accompanied by a certification from the owner or operator indicating whether the affected unit was in compliance with the applicable emission limits and minimum data requirements of this section during the reporting period. These quarterly reports must be submitted in PDF format to the EPA via CEDRI or analogous electronic reporting approach provided by the EPA to report data required by this section.

(5) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of EPA system outage for failure to timely comply with that reporting requirement. To assert a claim of EPA system outage, you must meet the requirements outlined in paragraphs (g)(5)(i) through (vii) of this section.

(i) You must have been or will be precluded from accessing CEDRI and submitting a required report within the time prescribed due to an outage of either the EPA's CEDRI or CDX systems.

(ii) The outage must have occurred within the period of time beginning five business days prior to the date that the submission is due.

(iii) The outage may be planned or unplanned.

(iv) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(v) You must provide to the Administrator a written description identifying:

(A) The date(s) and time(s) when CDX or CEDRI was accessed and the system was unavailable;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to EPA system outage;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(vi) The decision to accept the claim of EPA system outage and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(vii) In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved.

(6) If you are required to electronically submit a report through CEDRI in the EPA's CDX, you may assert a claim of force majeure for failure to timely comply with that reporting requirement. To assert a claim of force majeure, you must meet the requirements outlined in paragraphs (g)(6)(i) through (v) of this section.

(i) You may submit a claim if a force majeure event is about to occur, occurs, or has occurred or there are lingering effects from such an event within the period of time beginning five business days prior to the date the submission is due. For the purposes of this section, a force majeure event is defined as an event that will be or has been caused by circumstances beyond the control of the affected facility, its contractors, or any entity controlled by the affected facility that prevents you from complying with the requirement to submit a report electronically within the time period prescribed. Examples of such events are acts of nature (*e.g.,* hurricanes, earthquakes, or floods), acts of war or terrorism, or equipment failure or safety hazard beyond the control of the affected facility (*e.g.,* large scale power outage).

(ii) You must submit notification to the Administrator in writing as soon as possible following the date you first knew, or through due diligence should have known, that the event may cause or has caused a delay in reporting.

(iii) You must provide to the Administrator:

(A) A written description of the force majeure event;

(B) A rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event;

(C) A description of measures taken or to be taken to minimize the delay in reporting; and

(D) The date by which you propose to report, or if you have already met the reporting requirement at the time of the notification, the date you reported.

(iv) The decision to accept the claim of force majeure and allow an extension to the reporting deadline is solely within the discretion of the Administrator.

(v) In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs.

Subpart B—Alabama

■ 5. Amend § 52.54 by revising paragraphs (b)(2) and (3) and adding paragraphs (b)(4) and (5) to read as follows:

§ 52.54 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(3) The owner and operator of each source and each unit located in the State of Alabama and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the

promulgation of an approval by the Administrator of a revision to Alabama's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Alabama's SIP.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Alabama's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

Subpart E—Arkansas

■ 6. Amend § 52.184 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2), removing "2017 and each subsequent year." and adding in its place "2017 through 2022.", and removing the second sentence;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Arkansas and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Arkansas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Arkansas' SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Arkansas and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart F—California

■ 7. Add § 52.284 to read as follows:

§ 52.284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

The owner and operator of each source located in the State of California and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart I—Delaware

■ 8. Amend § 52.440 by adding paragraph (d) to read as follows:

§ 52.440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Delaware and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Delaware's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Delaware's SIP

revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

Subpart O—Illinois

■ 9. Amend § 52.731 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.731 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Illinois and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart P—Indiana

■ 10. Amend § 52.789 by:
■ a. In paragraph (b)(2), removing ''(b)(2)(iv), except'' and adding in its place ''(b)(2)(ii), except'';
■ b. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ c. Adding paragraph (c).

The addition reads as follows:

§ 52.789 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Indiana and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart S—Kentucky

■ 11. Amend § 52.940 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Kentucky and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart T—Louisiana

■ 12. Amend § 52.984 by:
■ a. In paragraph (d)(3), revising the second and third sentences;
■ b. Revising paragraph (d)(4);
■ c. In paragraph (d)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (e).

The revision and addition read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and(b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Louisiana's SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Louisiana's SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(e) The owner and operator of each source located in the State of Louisiana and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart V—Maryland

■ 13. Amend § 52.1084 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1084 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Maryland and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart X—Michigan

■ 14. Amend § 52.1186 by:
■ a. In paragraph (e)(3), revising the second and third sentences;
■ b. Revising paragraph (e)(4);
■ c. In paragraph (e)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (f).

The revision and addition read as follows:

§ 52.1186 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the

Administrator of a revision to Michigan's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and(b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Michigan's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Michigan's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(f) The owner and operator of each source located in the State of Michigan and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Y—Minnesota

■ 15. Amend § 52.1240 by adding paragraphs (d) and (e) to read as follows:

§ 52.1240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d)(1) The owner and operator of each source and each unit located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Minnesota's SIP.

(2) Notwithstanding the provisions of paragraph (d)(1) of this section, if, at the time of the approval of Minnesota's SIP revision described in paragraph (d)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(e) The owner and operator of each source located in the State of Minnesota and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart Z—Mississippi

■ 16. Amend § 52.1284 by:

■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);

■ b. In newly redesignated paragraph (a)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;

■ c. Revising newly redesignated paragraph (a)(3); and

■ d. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Mississippi's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Mississippi's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of

CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Mississippi and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart AA—Missouri

■ 17. Amend § 52.1326 by revising paragraph (b)(2) and (3) and adding paragraphs (b)(4) and (5) and (c) to read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(2) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 2 Trading Program in subpart EEEEE of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2017 through 2022. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(ii), except to the extent the Administrator's approval is partial or conditional.

(3) The owner and operator of each source and each unit located in the State of Missouri and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Missouri's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraphs (b)(2) and (3) of this section, if, at the time of the approval of Missouri's SIP revision described in paragraph (b)(2) or (3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances under subpart EEEEE or GGGGG, respectively, of part 97 of this chapter to units in the State for a control period in any year, the provisions of such subpart authorizing the Administrator to complete the allocation and recordation of such allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (b)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

(c) The owner and operator of each source located in the State of Missouri and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart DD—Nevada

■ 18. Add § 52.1492 to read as follows:

§ 52.1492 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Nevada's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Nevada's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Nevada and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart FF—New Jersey

■ 19. Amend § 52.1584 by:
■ a. In paragraph (e)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (f).

The addition reads as follows:

§ 52.1584 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(f) The owner and operator of each source located in the State of New Jersey and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart HH—New York

■ 20. Amend § 52.1684 by:
■ a. In paragraph (b)(3), revising the second and third sentences;
■ b. Revising paragraph (b)(4);
■ c. In paragraph (b)(5), adding ''and Indian country within the borders of the State'' after ''in the State''; and
■ d. Adding paragraph (c).

The revision and addition read as follows:

§ 52.1684 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(3) * * * The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to New York's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and(b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to New York's SIP.

(4) Notwithstanding the provisions of paragraph (b)(3) of this section, if, at the time of the approval of New York's SIP revision described in paragraph (b)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

* * * * *

(c) The owner and operator of each source located in the State of New York and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart KK—Ohio

■ 21. Amend § 52.1882 by:
■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and
■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.1882 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Ohio and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart LL—Oklahoma

■ 22. Amend § 52.1930 by:
■ a. Redesignating paragraphs (a) through (c) as paragraphs (a)(1) through (3);
■ b. In newly redesignated paragraph (a)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;
■ c. Revising newly redesignated paragraph (a)(3); and
■ c. Adding paragraphs (a)(4) and (5) and (b).

The revision and additions read as follows:

§ 52.1930 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(3) The owner and operator of each source and each unit located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Oklahoma's SIP.

(4) Notwithstanding the provisions of paragraph (a)(3) of this section, if, at the time of the approval of Oklahoma's SIP revision described in paragraph (a)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (a)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts

of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(b) The owner and operator of each source located in the State of Oklahoma and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart NN—Pennsylvania

■ 23. Amend § 52.2040 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2040 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Pennsylvania and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart RR—Tennessee

■ 24. Amend § 52.2240 by:

■ a. In paragraph (e)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second sentence;

■ b. Revising paragraph (e)(3); and

■ c. Adding paragraphs (e)(4) and (5).

The revision and additions read as follows:

§ 52.2240 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) The owner and operator of each source and each unit located in the State of Tennessee and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements will be eliminated by the promulgation of an approval by the Administrator of a revision to Tennessee's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii), except to the extent the Administrator's approval is partial or conditional.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Tennessee's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (e)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State for control periods after 2022) shall continue to apply.

Subpart SS—Texas

■ 25. Amend § 52.2283 by:

■ a. In paragraph (d)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;

■ b. Revising paragraph (d)(3); and

■ c. Adding paragraphs (d)(4) and (5) and (e).

The revision and additions read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(3) The owner and operator of each source and each unit located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Texas' SIP.

(4) Notwithstanding the provisions of paragraph (d)(3) of this section, if, at the time of the approval of Texas' SIP revision described in paragraph (d)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (d)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter

(concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(e) The owner and operator of each source located in the State of Texas and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart TT—Utah

■ 26. Add § 52.2356 to read as follows:

§ 52.2356 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Utah's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Utah's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Utah and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart VV—Virginia

■ 27. Amend § 52.2440 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2440 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart XX—West Virginia

■ 28. Amend § 52.2540 by:

■ a. In paragraph (b)(3), removing ''(b)(2)(v), except'' and adding in its place ''(b)(2)(iii), except''; and

■ b. Adding paragraph (c).

The addition reads as follows:

§ 52.2540 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(c) The owner and operator of each source located in the State of West Virginia and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart YY—Wisconsin

■ 29. Amend § 52.2587 by:

■ a. In paragraph (e)(2), removing ''2017 and each subsequent year.'' and adding in its place ''2017 through 2022.'', and removing the second and third sentences;

■ b. Revising paragraph (e)(3); and

■ c. Adding paragraphs (e)(4) and (5) and (f).

The revision and additions read as follows:

§ 52.2587 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(e) * * *

(3) The owner and operator of each source and each unit located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wisconsin's SIP.

(4) Notwithstanding the provisions of paragraph (e)(3) of this section, if, at the time of the approval of Wisconsin's SIP revision described in paragraph (e)(3) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart

GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(5) Notwithstanding the provisions of paragraph (e)(2) of this section, after 2022 the provisions of § 97.826(c) of this chapter (concerning the transfer of CSAPR NO_X Ozone Season Group 2 allowances between certain accounts under common control), the provisions of § 97.826(e) of this chapter (concerning the conversion of amounts of unused CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods before 2023 to different amounts of CSAPR NO_X Ozone Season Group 3 allowances), and the provisions of § 97.811(e) of this chapter (concerning the recall of CSAPR NO_X Ozone Season Group 2 allowances equivalent in quantity and usability to all such allowances allocated to units in the State and Indian country within the borders of the State for control periods after 2022) shall continue to apply.

(f) The owner and operator of each source located in the State of Wisconsin and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

Subpart ZZ—Wyoming

■ 30. Add § 52.2638 to read as follows:

§ 52.2638 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a)(1) The owner and operator of each source and each unit located in the State of Wyoming and Indian country within the borders of the State and for which requirements are set forth under the CSAPR NO_X Ozone Season Group 3 Trading Program in subpart GGGGG of part 97 of this chapter must comply with such requirements with regard to emissions occurring in 2023 and each subsequent year. The obligation to comply with such requirements with regard to sources and units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority will be eliminated by the promulgation of an approval by the Administrator of a revision to Wyoming State Implementation Plan (SIP) as correcting the SIP's deficiency that is the basis for the CSAPR Federal Implementation Plan (FIP) under § 52.38(b)(1) and (b)(2)(iii) for those sources and units, except to the extent the Administrator's approval is partial or conditional. The obligation to comply with such requirements with regard to sources and units located in areas of Indian country within the borders of the State not subject to the State's SIP authority will not be eliminated by the promulgation of an approval by the Administrator of a revision to Wyoming's SIP.

(2) Notwithstanding the provisions of paragraph (a)(1) of this section, if, at the time of the approval of Wyoming's SIP revision described in paragraph (a)(1) of this section, the Administrator has already started recording any allocations of CSAPR NO_X Ozone Season Group 3 allowances under subpart GGGGG of part 97 of this chapter to units in the State and areas of Indian country within the borders of the State subject to the State's SIP authority for a control period in any year, the provisions of subpart GGGGG of part 97 of this chapter authorizing the Administrator to complete the allocation and recordation of CSAPR NO_X Ozone Season Group 3 allowances to such units for each such control period shall continue to apply, unless provided otherwise by such approval of the State's SIP revision.

(b) The owner and operator of each source located in the State of Wyoming and Indian country within the borders of the State and for which requirements are set forth in § 52.40 and § 52.41, § 52.42, § 52.43, § 52.44, or § 52.45 must comply with such requirements with regard to emissions occurring in 2026 and each subsequent year.

PART 75—CONTINUOUS EMISSION MONITORING

■ 31. The authority citation for part 75 is revised to read as follows:

Authority: 42 U.S.C. 7401–7671q and 7651k note.

■ 32. Amend § 75.72 by:
■ a. In paragraph (c)(3), removing ''appendix B of this part.'' and adding in its place ''appendix B to this part.'';
■ b. In paragraph (e)(1)(ii), removing ''heat input from'' and adding in its place ''heat input rate to'';
■ c. In paragraph (e)(2), removing ''appendix D of this part'' and adding in its place ''appendix D to this part''; and
■ d. Adding paragraph (f).

The addition reads as follows:

§ 75.72 Determination of NO_X mass emissions for common stack and multiple stack configurations.

* * * * *

(f) *Procedures for apportioning hourly NO_X mass emission rate to the unit level.* If the owner or operator of a unit determining hourly NO_X mass emission rate at a common stack under this section is subject to a State or federal NO_X mass emissions reduction program under subpart GGGGG of part 97 of this chapter or under a state implementation plan approved pursuant to § 52.38(b)(12) of this chapter, then on and after January 1, 2024, the owner or operator shall apportion the hourly NO_X mass emissions rate at the common stack to each unit using the common stack based on the ratio of the hourly heat input rate for each such unit to the total hourly heat input rate for all such units, in conjunction with the appropriate unit and stack operating times, according to the procedures in section 8.5.3 of appendix F to this part.

* * * * *

■ 33. Amend § 75.73 by:
■ a. Revising paragraph (a)(3);
■ b. In paragraph (c)(1), removing ''No_X emissions'' and adding in its place ''NO_X emissions'';
■ c. Adding a paragraph heading to paragraph (c)(2);
■ d. Revising paragraphs (c)(3) and (f)(1) introductory text;
■ e. Removing and reserving paragraph (f)(1)(i)(B);
■ f. In paragraph (f)(1)(ii)(G), removing ''appendix D;'' and adding in its place ''appendix D to this part;'';
■ g. Adding paragraphs (f)(1)(ix) and (x);
■ h. Adding a paragraph heading to paragraph (f)(2); and
■ i. Revising paragraph (f)(4).

The revisions and addition reads as follows:

§ 75.73 Recordkeeping and reporting.

* * * * *

(a) * * *

(3) For each hour when the unit is operating, NO_X mass emission rate, calculated in accordance with section 8 of appendix F to this part.

* * * * *

(c) * * *

(2) *Monitoring plan updates.* * * *

(3) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in § 75.53(g)(1) in electronic format and the information in § 75.53(g)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53(h)(1)(i) and (h)(2)(i) in electronic format and the information in § 75.53(h)(1)(ii) and (h)(2)(ii) in hardcopy format. For units using the low mass emissions excepted methodology under § 75.19, the monitoring plan shall include the additional information in § 75.53(h)(4)(i) and (h)(4)(ii). The monitoring plan also

shall include a seasonal controls indicator and an ozone season fuel-switching flag.

(f) * * *

(1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly, unless the unit has been placed in long-term cold storage (as defined in § 72.2 of this chapter). Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the information provided in paragraphs (f)(1)(i) through (x) of this section and shall also include the date of report generation. A unit placed into long-term cold storage is exempted from submitting quarterly reports beginning with the calendar quarter following the quarter in which the unit is placed into long-term cold storage, provided that the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the unit recommences operation (where the initial quarterly report contains hourly data beginning with the first hour of recommenced operation of the unit).

* * * * *

(ix) On and after on January 1, 2024, for a unit subject to subpart GGGGG of part 97 of this chapter or a state implementation plan approved under § 52.38(b)(12) of this chapter and determining NO_X mass emission rate at a common stack, apportioned hourly NO_X mass emission rate for the unit, lb/hr.

(x) On and after January 1, 2024, for a unit subject to a backstop daily NO_X emission rate under subpart GGGGG of part 97 of this chapter or under a state implementation plan approved under § 52.38(b)(12) of this chapter:

(A) Daily NO_X emissions (lbs) for each day of the reporting period;

(B) Daily heat input (mmBtu) for each day of the reporting period;

(C) Daily average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) for each day of the reporting period;

(D) Daily NO_X emissions (lbs) exceeding the applicable backstop daily NO_X emission rate for each day of the reporting period; and

(E) Cumulative NO_X emissions (tons, rounded to the nearest tenth) exceeding the applicable backstop daily NO_X emission rate during the ozone season.

(2) *Verification of identification codes and formulas.* * * *

* * * * *

(4) *Electronic format, method of submission, and explanatory information.* The designated representative shall comply with all of the quarterly reporting requirements in § 75.64(d), (f), and (g).

■ 34. Revise § 75.75 to read as follows:

§ 75.75 Additional ozone season calculation procedures.

(a) The owner or operator of a unit that is required to calculate daily or ozone season heat input shall do so by summing the unit's hourly heat input determined according to the procedures in this part for all hours in which the unit operated during the day or ozone season.

(b) The owner or operator of a unit that is required to determine daily or ozone season NO_X emission rate (in lbs/mmBtu) shall do so by dividing daily or ozone season NO_X mass emissions (in lbs) determined in accordance with this subpart, by daily or ozone season heat input determined in accordance with paragraph (a) of this section.

■ 35. Amend appendix F to part 75 by:

■ a. Adding section 5.3.3;

■ b. In section 8.1.2, revising the introductory text preceding Equation F–25;

■ c. In section 8.4, revising the introductory text, paragraph (a) introductory text (preceding Equation F–27), and paragraph (b) introductory text (preceding Equation F–27a), and adding paragraph (c);

■ d. In section 8.5.2, removing ''the hourly NO_X mass emissions at each unit'' and adding in its place ''hourly NO_X mass emissions at the common stack.''; and

■ e. Adding section 8.5.3.

The additions and revisions read as follows

Appendix F to Part 75—Conversion Procedures

* * * * *

5.3.3 Calculate total daily heat input for a unit using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_d = \sum_{h=1}^{24} HI_h t_h \quad \text{(Eq. F-18c)}$$

Where:

HI_d = Total heat input for a unit for the day, mmBtu.

HI_h = Heat input rate for the unit for hour ''h'' from Equation F–15, F–16, F–17, F–18, F–21a, or F–21b, mmBtu/hr.

t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).

h = Designation of a particular hour.

* * * * *

8.1.2 If NO_X emission rate is measured at a common stack and heat input rate is measured at the unit level, calculate the hourly heat input rate at the common stack according to the following formula:

* * * * *

8.4 Use the following equations to calculate daily, quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions:

(a) When hourly NO_X mass emissions are reported in lb., use Eq. F–27 to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons. * * *

(b) When hourly NO_X mass emission rate is reported in lb/hr, use Eq. F–27a to calculate quarterly, cumulative ozone season, and cumulative year-to-date NO_X mass emissions in tons. * * *

(c) To calculate daily NO_X mass emissions for a unit in pounds, use Eq. F–27b.

$$M_{(NOX)_d} = \sum_{h=1}^{24} E_{(NOX)_h} t_h$$

(Eq. F-27b)

Where:

$M_{(NOX)_d}$ = NO_X mass emissions for a unit for the day, pounds.
$E_{(NOX)_h}$ = NO_X mass emission rate for the unit for hour "h" from Equation F–24a, F–26a, F–26b, or F–28, lb/hr.
t_h = Unit operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).
h = Designation of a particular hour.

* * * * *

8.5.3 Where applicable, the owner or operator of a unit that determines hourly NO_X mass emission rate at a common stack shall apportion hourly NO_X mass emissions rate to the units using the common stack based on the hourly heat input rate, using Equation F–28:

$$E_{(NOX)_i} = E_{(NOX)_{CS}} \left(\frac{t_{CS}}{t_i}\right)\left[\frac{HI_i t_i}{\sum_{i=1}^{n} HI_i t_i}\right]$$

(Eq. F-28)

Where:

$E_{(NOX)_i}$ = Apportioned NO_X mass emission rate for unit "i", lb/hr.
$E_{(NOX)_{CS}}$ = NO_X mass emission rate at the common stack, lb/hr.
HI_i = Heat input rate for unit "i", mmBtu/hr.
t_i = Operating time for unit "i", fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).
t_{CS} = Common stack operating time, fraction of the hour (0.00 to 1.00, in equal increments from one hundredth to one quarter of an hour, at the option of the owner or operator).
n = Number of units using the common stack.
i = Designation of a particular unit.

PART 78—APPEAL PROCEDURES

■ 36. The authority citation for part 78 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

■ 37. Amend § 78.1 by:
■ a. In paragraph (b)(17)(viii), adding "or (e)" after "§ 97.826(d)";
■ b. In paragraph (b)(17)(ix), adding "or (e)" after "§ 97.811(d)"; and
■ c. Revising paragraph (b)(19).

The revision reads as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(19) Under subpart GGGGG of part 97 of this chapter,

(i) The decision on the calculation of a state CSAPR NO_X Ozone Season Group 3 trading budget under § 97.1010(a)(3) of this chapter.

(ii) The decision on the allocation of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1011 or § 97.1012 of this chapter.

(iii) The decision on the transfer of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1023 of this chapter.

(iv) The decision on the deduction of CSAPR NO_X Ozone Season Group 3 allowances under § 97.1024, § 97.1025, or § 97.1026(d) of this chapter.

(v) The correction of an error in an Allowance Management System account under § 97.1027 of this chapter.

(vi) The adjustment of information in a submission and the decision on the deduction and transfer of CSAPR NO_X Ozone Season Group 3 allowances based on the information as adjusted under § 97.1028 of this chapter.

(vii) The finalization of control period emissions data, including retroactive adjustment based on audit.

(viii) The approval or disapproval of a petition under § 97.1035 of this chapter.

* * * * *

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, CSAPR NO_X AND SO_2 TRADING PROGRAMS, AND TEXAS SO_2 TRADING PROGRAM

■ 38. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7491, 7601, and 7651, *et seq.*

Subpart AAAAA—CSAPR NO_X Annual Trading Program

§ 97.402 [Amended]

■ 39. Amend § 97.402 by:
■ a. In the definition of "CSAPR NO_X Ozone Season Group 1 Trading Program", removing "(b)(2)(i) and (ii), and" and adding in its place "(b)(2)(i), and";
■ b. In the definition of "CSAPR NO_X Ozone Season Group 2 Trading Program", removing "(b)(2)(iii) and (iv), and" and adding in its place "(b)(2)(ii), and"; and
■ c. In the definition of "CSAPR NO_X Ozone Season Group 3 Trading Program", removing "(b)(2)(v), and" and adding in its place "(b)(2)(iii), and";

§ 97.411 [Amended]

■ 40. Amend § 97.411 by:
■ a. In paragraphs (b)(1)(i)(A) and (B), removing "State, in accordance" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance"; and
■ b. In paragraphs (b)(2)(i)(A) and (B), removing "Indian country within the borders of a State, in accordance" and adding in its place "areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance".

§ 97.412 [Amended]

■ 41. Amend § 97.412 by:
■ a. In paragraph (a) introductory text, removing "State, the Administrator" and adding in its place "State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator";
■ b. In paragraphs (a)(3)(iii) and (a)(5), adding "and areas of Indian country within the borders of the State subject to the State's SIP authority" after "in the State";
■ c. In paragraph (a)(10), removing "State, is allocated" and adding in its place "State and areas of Indian country

within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.421 [Amended]

■ 42. In § 97.421, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.426 [Amended]

■ 43. In § 97.426, amend paragraph (c) by removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart BBBBB—CSAPR NO_X Ozone Season Group 1 Trading Program

§ 97.502 [Amended]

■ 44. Amend § 97.502 by:

■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'', adding ''or (e)'' after ''§ 97.826(d)'', and adding ''or less'' after ''one ton'';

■ d. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and

■ e. In the definition of ''State'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and''.

§ 97.511 [Amended]

■ 45. Amend § 97.511 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.512 [Amended]

■ 46. Amend § 97.512 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.521 [Amended]

■ 47. In § 97.521, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

■ 48. Amend § 97.526 by:

■ a. In paragraph (c), removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ b. In paragraph (d)(1) introductory text, removing ''§ 52.38(b)(2)(i) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(i)(A) of this chapter (and'';

■ c. In paragraph (d)(1)(ii), removing ''except a State listed in § 52.38(b)(2)(i)'' and adding in its place ''listed in § 52.38(b)(2)(ii)'';

■ d. In paragraph (d)(1)(iv), removing ''§ 52.38(b)(2)(iii) or (iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii) of this chapter (and'';

■ e. Revising paragraph (d)(2)(i);

■ f. In paragraph (d)(2)(ii), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and'';

■ g. Adding paragraph (d)(2)(iii);

■ h. In paragraph (e)(1), removing ''chapter (or Indian'' and adding in its place ''chapter (and Indian'';

■ i. In paragraph (e)(2), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii)(A) of this chapter (and''; and

■ j. Adding paragraph (e)(3).

The revisions and additions read as follows:

§ 97.526 Banking and conversion.

* * * * *

(d) * * *

(2)(i) Except as provided in paragraphs (d)(2)(ii) and (iii) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(ii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 2 allowances for the control period in 2017 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section.

* * * * *

(iii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

* * * * *

(e) * * *

(3) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.826(e)(1), the owner or operator of a CSAPR NO_X Ozone Season Group 1

source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(e)(1)(ii).

Subpart CCCCC—CSAPR SO_2 Group 1 Trading Program

§ 97.602 [Amended]

■ 49. Amend § 97.602 by:

■ a. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and'';

§ 97.611 [Amended]

■ 50. Amend § 97.611 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.612 [Amended]

■ 51. Amend § 97.612 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.621 [Amended]

■ 52. In § 97.621, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.626 [Amended]

■ 53. In § 97.626, amend paragraph (c) by removing ''State (or Indian'' and adding in its place ''State (and Indian''.

Subpart DDDDD—CSAPR SO_2 Group 2 Trading Program

■ 54. Amend § 97.702 by:

■ a. In the definition of ''alternate designated representative'', removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 1 Trading Program'', removing ''(b)(2)(i) and (ii), and'' and adding in its place ''(b)(2)(i), and'';

■ c. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ d. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and

■ e. In the definition of ''designated representative'', removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

§ 97.702 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.711 [Amended]

■ 55. Amend § 97.711 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance''; and

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance''.

§ 97.712 [Amended]

■ 56. Amend § 97.712 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.721 [Amended]

■ 57. In § 97.721, amend paragraph (f)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.726 [Amended]

■ 58. In § 97.726, amend paragraph (c) by removing ''State (or Indian'' and adding in its place ''State (and Indian''.

§ 97.734 [Amended]

■ 59. In § 97.734, amend paragraph (d)(3) by removing ''or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

■ 60. Amend § 97.802 by:

■ a. In the definition of ''assurance account'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ b. Removing the definitions for ''base CSAPR NO_X Ozone Season Group 2 source'' and ''base CSAPR NO_X Ozone Season Group 2 unit'';

■ c. In the definition of ''common designated representative'', removing ''base CSAPR'' and adding in its place ''CSAPR'';

■ d. In the definition of ''common designated representative's assurance level'', revising paragraph (1);

■ e. In the definition of ''common designated representative's share'', removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears;

■ f. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ g. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'', adding ''or (e)'' after ''§ 97.826(d)'', and adding ''or less'' after ''one ton'';

■ h. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''; and

■ i. In the definition of ''State'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and''.

The revision reads as follows:

§ 97.802 Definitions.

* * * * *

Common designated representative's assurance level * * *

(1) The amount (rounded to the nearest allowance) equal to the sum of the total amount of CSAPR NO_X Ozone Season Group 2 allowances allocated for such control period to the group of one or more CSAPR NO_X Ozone Season Group 2 units in such State (and such Indian country) having the common designated representative for such control period and the total amount of CSAPR NO_X Ozone Season Group 2 allowances purchased by an owner or operator of such CSAPR NO_X Ozone Season Group 2 units in an auction for such control period and submitted by the State or the permitting authority to the Administrator for recordation in the compliance accounts for such CSAPR NO_X Ozone Season Group 2 units in accordance with the CSAPR NO_X Ozone Season Group 2 allowance auction provisions in a SIP revision approved by the Administrator under § 52.38(b)(8) or (9) of this chapter, multiplied by the sum of the State NO_X Ozone Season Group 2 trading budget under § 97.810(a) and the State's variability limit under § 97.810(b) for such control period, and divided by such State NO_X Ozone Season Group 2 trading budget;

* * * * *

§ 97.806 [Amended]

■ 61. In § 97.806, amend paragraphs (c)(2)(i) introductory text, (c)(2)(i)(B), (c)(2)(iii) and (iv), and (c)(3)(ii) by removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears.

§ 97.810 [Amended]

■ 62. In § 97.810, amend paragraphs (a)(1)(i) through (iii), (a)(2)(i) and (ii), (a)(12)(i) through (iii), (a)(13)(i) and (ii), (a)(17)(i) through (iii), (a)(19)(i) and (ii), (a)(20)(i) through (iii), (a)(23)(i) through (iii), and (b)(1), (2), (12), (13), (17), (19), (20), and (23) by removing ''and thereafter'' and adding in its place ''through 2022''.

■ 63. Amend § 97.811 by:

■ a. In paragraphs (b)(1)(i)(A) and (B), removing ''State, in accordance'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, in accordance'';

■ b. In paragraphs (b)(2)(i)(A) and (B), removing ''Indian country within the borders of a State, in accordance'' and adding in its place ''areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance'';

■ c. In paragraph (d)(1), removing ''§ 52.38(b)(2)(iv) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(ii)(B) of this chapter (and''; and

■ d. Adding paragraph (e).

The addition reads as follows:

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

* * * * *

(e) *Recall of CSAPR NO_X Ozone Season Group 2 allowances allocated for control periods after 2022.* (1) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b) of this chapter, the provisions of this paragraph and paragraphs (e)(2) through (7) of this section shall apply with regard to each CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period after 2022 to any unit (including a permanently retired unit qualifying for an exemption under § 97.805) in a State listed in § 52.38(b)(2)(ii)(C) of this chapter (and Indian country within the borders of such a State) and that was initially recorded in the compliance account for the source that includes the unit, whether such CSAPR NO_X Ozone Season Group 2 allowance was allocated pursuant to this subpart or pursuant to a SIP revision approved under § 52.38(b) of this chapter and whether such CSAPR NO_X Ozone Season Group 2 allowance remains in such compliance account or has been transferred to another Allowance Management System account.

(2)(i) For each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section that was allocated for a given control period and initially recorded in a given source's compliance account, one CSAPR NO_X Ozone Season Group 2 allowance that was allocated for the same or an earlier control period and initially recorded in the same or any other Allowance Management System account must be surrendered in accordance with the procedures in paragraphs (e)(3) and (4) of this section.

(ii)(A) The surrender requirement under paragraph (e)(2)(i) of this section corresponding to each CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section initially recorded in a given source's compliance account shall apply to such source's current owners and operators, except as provided in paragraph (e)(2)(ii)(B) of this section.

(B) If the owners and operators of a given source as of a given date assumed ownership and operational control of the source through a transaction that did not also provide rights to direct the use or transfer of a given CSAPR NO_X Ozone Season Group 2 allowance described in paragraph (e)(1) of this section with regard to such source (whether recordation of such CSAPR NO_X Ozone Season Group 2 allowance in the source's compliance account occurred before such transaction or was anticipated to occur after such transaction), then the surrender requirement under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowance shall apply to the most recent former owners and operators of the source before the occurrence of such a transaction.

(C) The Administrator will not adjudicate any private legal dispute among the owners and operators of a source or among the former owners and operators of a source, including any disputes relating to the requirements to surrender CSAPR NO_X Ozone Season Group 2 allowances for the source under paragraph (e)(2)(i) of this section.

(3)(i) As soon as practicable on or after [EFFECTIVE DATE OF FINAL RULE], the Administrator will send a notification to the designated representative for each source described in paragraph (e)(1) of this section identifying the amounts of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account and the corresponding surrender requirements for the source under paragraph (e)(2)(i) of this section.

(ii) As soon as practicable on or after [15 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will deduct from the compliance account for each source described in paragraph (e)(1) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such compliance account.

(iii) As soon as practicable after completion of the deductions under paragraph (e)(3)(ii) of this section, the Administrator will identify for each source described in paragraph (e)(1) of this section the amounts, if any, of CSAPR NO_X Ozone Season Group 2 allowances allocated for each control period after 2022 and recorded in the source's compliance account for which the corresponding surrender requirements under paragraph (e)(2)(i) of this section have not been satisfied and will send a notification concerning such identified amounts to the designated representative for the source.

(iv) With regard to each source for which unsatisfied surrender requirements under paragraph (e)(2)(i) of this section remain after the deductions under paragraph (e)(3)(ii) of this section:

(A) Except as provided in paragraph (e)(3)(iv)(B) of this section, not later than September 15, 2023, the owners and operators of the source shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such unsatisfied surrender requirements under paragraph (e)(2)(i) of this section in the source's compliance account.

(B) With regard to any portion of such unsatisfied surrender requirements that apply to former owners and operators of the source pursuant to paragraph (e)(2)(ii)(B) of this section, not later than September 15, 2023, such former owners and operators shall hold sufficient CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such portion of the unsatisfied surrender requirements under paragraph (e)(2)(i) of this section either in the source's compliance account or in another Allowance Management System account identified to the Administrator on or before such date in a submission by the authorized account representative for such account.

(C) As soon as practicable on or after September 15, 2023, the Administrator will deduct from the Allowance Management System account identified in accordance with paragraph (e)(3)(iv)(A) or (B) of this section CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy the surrender requirements for the source under paragraph (e)(2)(i) of this section until all such surrender requirements for the source are satisfied or until no more CSAPR NO_X Ozone Season Group 2 allowances eligible to satisfy such surrender requirements remain in such account.

(v) When making deductions under paragraph (e)(3)(ii) or (iv) of this section to address the surrender requirements under paragraph (e)(2)(i) of this section for a given source:

(A) The Administrator will make deductions to address any surrender requirements with regard to first the 2023 control period and then the 2024 control period.

(B) When making deductions to address the surrender requirements with regard to a given control period, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for such given control period and will then deduct CSAPR NO_X Ozone Season Group 2 allowances allocated for each successively earlier control period in sequence.

(C) When deducting CSAPR NO_X Ozone Season Group 2 allowances allocated for a given control period from a given Allowance Management System account, the Administrator will first deduct CSAPR NO_X Ozone Season Group 2 allowances initially recorded in the account under § 97.821 (if the account is a compliance account) in the order of recordation and will then deduct CSAPR NO_X Ozone Season Group 2 allowances recorded in the account under § 97.526(d) or § 97.823 in the order of recordation.

(4)(i) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraph (e)(3) of this section, as soon as practicable on or after November 15, 2023, the Administrator will deduct such initially recorded CSAPR NO_X Ozone Season Group 2 allowances from any Allowance Management System accounts in which such CSAPR NO_X Ozone Season Group 2 allowances are held, making such deductions in any order determined by the Administrator, until all such surrender requirements for such source have been satisfied or until all such CSAPR NO_X Ozone Season Group 2 allowances have been deducted, except as provided in paragraph (e)(4)(ii) of this section.

(ii) If no person with an ownership interest in a given CSAPR NO_X Ozone Season Group 2 allowance as of April 30, 2022, was an owner or operator of the source in whose compliance account such CSAPR NO_X Ozone Season Group 2 allowance was initially recorded, was a direct or indirect parent or subsidiary of an owner or operator of such source, or was directly or indirectly under common ownership with an owner or operator of such source, the Administrator will not deduct such CSAPR NO_X Ozone Season Group 2 allowance under paragraph (e)(4)(i) of this section. For purposes of this paragraph, each owner or operator of a source shall be deemed to be a person with an ownership interest in any CSAPR NO_X Ozone Season Group 2 allowance held in that source's compliance account. The limitation established by this paragraph on the deductibility of certain CSAPR NO_X Ozone Season Group 2 allowances under paragraph (e)(4)(i) of this section shall not be construed as a waiver of the surrender requirements under paragraph (e)(2)(i) of this section corresponding to such CSAPR NO_X Ozone Season Group 2 allowances.

(iii) Not less than 45 days before the planned date for any deductions under paragraph (e)(4)(i) of this section, the Administrator will send a notification to the authorized account representative for the Allowance Management System account from which such deductions will be made identifying the CSAPR NO_X Ozone Season Group 2 allowances to be deducted and the data upon which the Administrator has relied and specifying a process for submission of any objections to such data. Any objections must be submitted to the Administrator not later than 15 days before the planned date for such deductions as indicated in such notification.

(5) To the extent the surrender requirements under paragraph (e)(2)(i) of this section corresponding to any CSAPR NO_X Ozone Season Group 2 allowances allocated for a control period after 2022 and initially recorded in a given source's compliance account have not been fully satisfied through the deductions under paragraphs (e)(3) and (4) of this section:

(i) The persons identified in accordance with paragraph (e)(2)(ii) of this section with regard to such source and each such CSAPR NO_X Ozone Season Group 2 allowance shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(ii) Each such CSAPR NO_X Ozone Season Group 2 allowance, and each day in such control period, shall constitute a separate violation of this subpart and the Clean Air Act.

(6) The Administrator will record in the appropriate Allowance Management System accounts all deductions of CSAPR NO_X Ozone Season Group 2 allowances under paragraphs (e)(3) and (4) of this section.

(7)(i) Each submission, objection, or other written communication from a designated representative, authorized account representative, or other person to the Administrator under paragraph (e)(2), (3), or (4) of this section shall be sent electronically to the email address *CSAPR@epa.gov.* Each such communication from a designated representative must contain the certification statement set forth in § 97.814(a), and each such communication from the authorized account representative for a general account must contain the certification statement set forth in § 97.820(c)(2)(ii).

(ii) Each notification from the Administrator to a designated representative or authorized account representative under paragraph (e)(3) or (4) of this section will be sent electronically to the email address most recently received by the Administrator for such representative. In any such notification, the Administrator may provide information by means of a reference to a publicly accessible website where the information is available.

§ 97.812 [Amended]

■ 64. Amend § 97.812 by:

■ a. In paragraph (a) introductory text, removing ''State, the Administrator'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, the Administrator'';

■ b. In paragraphs (a)(3)(iii) and (a)(5), adding ''and areas of Indian country within the borders of the State subject to the State's SIP authority'' after ''in the State'';

■ c. In paragraph (a)(10), removing ''State, is allocated'' and adding in its place ''State and areas of Indian country within the borders of the State subject to the State's SIP authority, is allocated'';

■ d. In paragraph (b) introductory text, removing ''Indian country within the borders of each State, the Administrator'' and adding in its place ''areas of Indian country within the borders of each State not subject to the State's SIP authority, the Administrator''; and

■ e. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority''.

§ 97.821 [Amended]

■ 65. In § 97.821, amend paragraph (f) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.825 [Amended]

■ 66. In § 97.825, amend paragraphs (a) introductory text, (a)(2), (b)(1)(i), (b)(1)(ii)(A) and (B), (b)(3), (b)(4)(i), (b)(5), (b)(6)(i), (b)(6)(iii) introductory text, and (b)(6)(iii)(A) and (B) by removing ''base CSAPR'' and adding in its place ''CSAPR'' each time it appears.

■ 67. Amend § 97.826 by:

■ a. In paragraph (b), removing ''(c) or (d)'' and adding in its place ''(c), (d), or (e)'';

■ b. In paragraph (c), removing ''State (or Indian'' and adding in its place ''State (and Indian'';

■ c. In paragraphs (d)(1)(i)(A) and (B), removing ''§ 52.38(b)(2)(iv)'' and adding in its place ''§ 52.38(b)(2)(ii)(B)'';

■ d. Revising paragraph (d)(1)(i)(C);

■ e. In paragraph (d)(1)(ii) introductory text, removing ''§ 52.38(b)(2)(v)'' and adding in its place ''§ 52.38(b)(2)(iii)'';

■ f. Removing and reserving paragraph (d)(1)(iii);

■ g. Revising paragraph (d)(1)(iv) introductory text;

■ h. In paragraphs (d)(1)(iv)(A) and (B), removing ''or (d)(1)(iii)(C)'';

■ i. In paragraphs (d)(2)(i) and (d)(3), removing ''§ 52.38(b)(2)(v) of this chapter (or'' and adding in its place ''§ 52.38(b)(2)(iii) of this chapter (and'';

■ j. Redesignating paragraph (e) as paragraph (f) and adding a new paragraph (e);

■ k. Revising newly redesignated paragraphs (f)(1) and (2); and

■ l. Adding paragraph (f)(3).

The revisions and additions read as follows:

§ 97.826 Banking and conversion.

* * * * *

(d) * * *

(1) * * *

(i) * * *

(C) The full-season CSAPR NO_X Ozone Season Group 3 allowance bank target, computed as the sum for all States listed in § 52.38(b)(2)(iii)(A) of this chapter of the variability limits under § 97.1010(e) for such States for the control period in 2022.

* * * * *

(iv) For the compliance account of each source to which an amount of CSAPR NO_X Ozone Season Group 3 allowances greater than zero is allocated under paragraph (d)(1)(ii)(C) of this section:

* * * * *

(e) Notwithstanding any other provision of this subpart, part 52 of this chapter, or any SIP revision approved under § 52.38(b)(8) or (9) of this chapter:

(1) By [45 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 2 allowance transfers submitted under § 97.822 and, before resuming acceptance of such transfers, will take the following actions with regard to every general account and every compliance account except a compliance account for a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(A) of this chapter (and Indian country within the borders of such a State):

(i) The Administrator will deduct all CSAPR NO_X Ozone Season Group 2 allowances allocated for the control periods in 2017 through 2022 from each such account.

(ii) The Administrator will determine a conversion factor equal to the greater of 1.0000 or the quotient, expressed to four decimal places, of the sum of all CSAPR NO_X Ozone Season Group 2 allowances deducted from all such accounts under paragraph (e)(1)(i) of this section divided by the sum of the variability limits for the control period in 2024 under § 97.1010(e) for all States listed in § 52.38(b)(2)(iii)(B) of this chapter.

(iii) The Administrator will allocate and record in each such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of the number of CSAPR NO_X Ozone Season Group 2 allowances deducted from such account under paragraph (e)(1)(i) of this section divided by the conversion factor determined under paragraph (e)(1)(ii) of this section, except as provided in paragraph (e)(1)(iv) or (v) of this section.

(iv) Where, pursuant to paragraph (e)(1)(i) of this section, the Administrator deducts CSAPR NO_X Ozone Season Group 2 allowances from the compliance account for a source in a State not listed in § 52.38(b)(2)(iii) of this chapter (and Indian country within the borders of such a State), the Administrator will not record CSAPR NO_X Ozone Season Group 3 allowances in that compliance account but instead will allocate and record the amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed for such source in accordance with paragraph (e)(1)(iii) of this section in a general account identified by the designated representative for such source, provided that if the designated representative fails to identify such a general account in a submission to the Administrator by [45 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator may record such CSAPR NO_X Ozone Season Group 3 allowances in a general account identified or established by the Administrator with the designated representative as the authorized account representative and with the owners and operators of such source (as indicated on the certificate of representation for the source) as the persons represented by the authorized account representative.

(v)(A) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be allocated to and recorded in general accounts under paragraph (e)(1)(iii) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(B) Following a computation for a group of general accounts in accordance with paragraph (e)(1)(v)(A) of this section, the Administrator will allocate to and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 2 allowances removed from such individual accounts under paragraph (e)(1)(i) of this section.

(C) In determining the proportional shares under paragraph (e)(1)(v)(B) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (e)(1)(v)(A) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances allocated to some individual accounts to equal zero.

(2) After the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 2 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 2 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

(f) * * *

(1) Except as provided in paragraph (f)(3) of this section, after the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(iii)(A) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for the control period in a year from 2017 through 2020 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (d)(1)(i)(D) of this section.

(2) Except as provided in paragraph (f)(3) of this section, after the Administrator has carried out the procedures set forth in paragraph (e)(1) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(iii)(B) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 2 allowances for the control period in a year from 2017 through 2022 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.1002 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 2 allowances divided by the conversion factor determined under paragraph (e)(1)(ii) of this section.

(3) CSAPR NO_X Ozone Season Group 3 allowances may not be used to satisfy requirements to surrender CSAPR NO_X Ozone Season Group 2 allowances under § 97.811(d) or (e).

Subpart FFFFF—Texas SO_2 Trading Program

■ 68. Amend § 97.902 by:

■ a. In the definition of ''alternate designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then'';

■ b. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';

■ c. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 Trading Program''; and

■ d. In the definition of ''designated representative'', removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, then'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, then''.

The addition reads as follows:

§ 97.902 Definitions.

* * * * *

CSAPR NO_X Ozone Season Group 3 Trading Program means a multi-state

NO_X air pollution control and emission reduction program established in accordance with subpart GGGGG of this part and § 52.38(b)(1), (b)(2)(iii), and (b)(10) through (14) and (17) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(10) or (11) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(12) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

§ 97.921 [Amended]

■ 69. In § 97.921, amend paragraph (b)(2) by removing ''2022'' and adding in its place ''2024'', and removing ''third'' before ''year after the year''.

§ 97.934 [Amended]

■ 70. In § 97.934, amend paragraph (d)(3) by removing ''Program or CSAPR NO_X Ozone Season Group 2 Trading Program, quarterly'' and adding in its place ''Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, quarterly''.

Subpart GGGGG—CSAPR NO_X Ozone Season Group 3 Trading Program

■ 71. Amend § 97.1002 by:
■ a. Revising the definition of ''allocate or allocation'';
■ b. In the definition of ''allowance transfer deadline'', adding ''primary'' before ''emissions limitation'';
■ c. In the definition of ''alternate designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then'';
■ d. Adding in alphabetical order a definition for ''backstop daily NO_X emissions rate'';
■ e. In the definition of ''common designated representative's assurance level'', in paragraph (1), removing ''§ 97.1010(b)'' and adding in its place ''§ 97.1010(e)'', and revising paragraph (2);
■ f. In the definition of ''compliance account'', adding ''primary'' before ''emissions limitation'';
■ g. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 1 Trading Program'';
■ h. In the definition of ''CSAPR NO_X Ozone Season Group 2 Trading Program'', removing ''(b)(2)(iii) and (iv), and'' and adding in its place ''(b)(2)(ii), and'';
■ i. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance'', adding ''or (e)'' after ''§ 97.826(d)'', and adding ''or less'' after ''one ton'';
■ j. In the definition of ''CSAPR NO_X Ozone Season Group 3 allowance deduction or deduct CSAPR NO_X Ozone Season Group 3 allowances'', adding ''primary'' before ''emissions limitation'';
■ k. In the definition of ''CSAPR NO_X Ozone Season Group 3 emissions limitation'', adding ''primary'' before ''emissions limitation'';
■ l. Adding in alphabetical order a definition for ''CSAPR NO_X Ozone Season Group 3 secondary emissions limitation'';
■ m. In the definition of ''CSAPR NO_X Ozone Season Group 3 Trading Program'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and'';
■ n. Adding in alphabetical order a definition for ''CSAPR SO_2 Group 2 Trading Program'';
■ o. In the definition of ''designated representative'', removing ''or CSAPR SO_2 Group 1 Trading Program, then'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, then''.
■ p. In the definition of ''excess emissions'', adding ''primary'' before ''emissions limitation''; and
■ q. In the definition of ''State'', removing ''(b)(2)(v), and'' and adding in its place ''(b)(2)(iii), and''.

The revisions and additions read as follows:

§ 97.1002 Definitions.

* * * * *

Allocate or *allocation* means, with regard to CSAPR NO_X Ozone Season Group 3 allowances, the determination by the Administrator, State, or permitting authority, in accordance with this subpart, §§ 97.526(d) and 97.826(d) and (e), and any SIP revision submitted by the State and approved by the Administrator under § 52.38(b)(10), (11), or (12) of this chapter, of the amount of such CSAPR NO_X Ozone Season Group 3 allowances to be initially credited, at no cost to the recipient, to:

(1) A CSAPR NO_X Ozone Season Group 3 unit;

(2) A new unit set-aside;

(3) An Indian country new unit set-aside;

(4) An Indian country existing unit set-aside; or

(5) An entity not listed in paragraphs (1) through (4) of this definition;

(6) Provided that, if the Administrator, State, or permitting authority initially credits, to a CSAPR NO_X Ozone Season Group 3 unit qualifying for an initial credit, a credit in the amount of zero CSAPR NO_X Ozone Season Group 3 allowances, the CSAPR NO_X Ozone Season Group 3 unit will be treated as being allocated an amount (*i.e.,* zero) of CSAPR NO_X Ozone Season Group 3 allowances.

* * * * *

Backstop daily NO_X emissions rate means an emissions rate limit used in the determination of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation for a CSAPR NO_X Ozone Season Group 3 source in accordance with § 97.1024(b).

* * * * *

Common designated representative's assurance level * * *

(2) Provided that the allocations of CSAPR NO_X Ozone Season Group 3 allowances for any control period taken into account for purposes of this definition shall exclude any CSAPR NO_X Ozone Season Group 3 allowances allocated for such control period under § 97.526(d) or § 97.826(d) or (e).

* * * * *

CSAPR NO_X Ozone Season Group 1 Trading Program means a multi-state NO_X air pollution control and emission reduction program established in accordance with subpart BBBBB of this part and § 52.38(b)(1), (b)(2)(i), and (b)(3) through (5) and (13) through (15) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.38(b)(3) or (4) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.38(b)(5) of this chapter), as a means of mitigating interstate transport of ozone and NO_X.

* * * * *

CSAPR NO_X Ozone Season Group 3 secondary emissions limitation means, for a CSAPR NO_X Ozone Season Group 3 unit to which such a limitation applies under § 97.1025(c)(1) for a control period in a given year, the tonnage of NO_X emissions calculated for the unit in accordance with § 97.1025(c)(2) for such control period.

* * * * *

CSAPR SO_2 Group 2 Trading Program means a multi-state SO_2 air pollution control and emission reduction program established in accordance with subpart DDDDD of this part and § 52.39(a), (c), (g) through (k), and (m) of this chapter (including such a program that is revised in a SIP revision approved by the Administrator under § 52.39(g) or (h) of this chapter or that is established in a SIP revision approved by the Administrator under § 52.39(i) of this chapter), as a means of mitigating interstate transport of fine particulates and SO_2.

* * * * *

■ 72. Amend § 97.1006 by:

■ a. Revising paragraph (b)(2), the paragraph (c)(1) heading, paragraph (c)(1)(i), and paragraph (c)(1)(ii) introductory text;

■ b. Adding paragraphs (c)(1)(iii) and (iv); and

■ c. Revising paragraphs (c)(2)(iii) and (c)(3).

The revisions and additions read as follows:

§ 97.1006 Standard requirements.

* * * * *

(b) * * *

(2) The emissions and heat input data determined in accordance with §§ 97.1030 through 97.1035 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 3 allowances under §§ 97.1011 and 97.1012 and to determine compliance with the CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations and assurance provisions under paragraph (c) of this section, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with §§ 97.1030 through 97.1035 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) * * *

(1) *CSAPR NO_X Ozone Season Group 3 primary and secondary emissions limitations*—(i) *Primary emissions limitation.* As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 3 source and each CSAPR NO_X Ozone Season Group 3 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 3 allowances available for deduction for such control period under § 97.1024(a) in an amount not less than the amount determined under § 97.1024(b), comprising the sum of:

(A) The tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 3 units at the source; plus

(B) Two times the sum, for all CSAPR NO_X Ozone Season Group 3 units at the source and all days of the control period, of any NO_X emissions from such a unit on any day of the control period exceeding the NO_X emissions that would have occurred on that day if the unit had combusted the same daily heat input and emitted at any backstop daily NO_X emissions rate applicable to the unit for that control period.

(ii) *Exceedances of primary emissions limitation.* If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 3 units at a CSAPR NO_X Ozone Season Group 3 source are in excess of the CSAPR NO_X Ozone Season Group 3 primary emissions limitation set forth in paragraph (c)(1)(i) of this section, then:

* * * * *

(iii) *Secondary emissions limitation.* The owner or operator of a base CSAPR NO_X Ozone Season Group 3 unit subject to an emissions limitation under § 97.1025(c)(1) shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with § 97.1025(c)(2).

(iv) *Exceedances of secondary emissions limitation.* If total NO_X emissions during a control period in a given year from a base CSAPR NO_X Ozone Season Group 3 unit are in excess of the amount of a CSAPR NO_X Ozone Season Group 3 secondary emissions limitation applicable to the unit for the control period under paragraph (c)(1)(iii) of this section, then the owners and operators of the unit and the source at which the unit is located shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart and the Clean Air Act.

(2) * * *

(iii) Total NO_X emissions from all base CSAPR NO_X Ozone Season Group 3 units at base CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) during a control period in a given year exceed the State assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 3 trading budget under § 97.1010(a) and the State's variability limit under § 97.1010(e).

* * * * *

(3) *Compliance periods.*(i) A CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(i) and (ii) of this section, and a base CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraph (c)(2) of this section, for the control period starting on the later of the applicable date in paragraph (c)(3)(i)(A), (B), or (C) of this section or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter:

(A) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) [EFFECTIVE DATE OF FINAL RULE], for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter.

(ii) A base CSAPR NO_X Ozone Season Group 3 unit shall be subject to the requirements under paragraphs (c)(1)(iii) and (iv) of this section for the control period starting on the later of May 1, 2024 or the deadline for meeting the unit's monitor certification requirements under § 97.1030(b) and for each control period thereafter.

* * * * *

■ 73. Revise § 97.1010 to read as follows:

§ 97.1010 State NO_X Ozone Season Group 3 trading budgets, set-asides, and variability limits.

(a) *State NO_X Ozone Season Group 3 trading budgets.* (1)(i) The State NO_X Ozone Season Group 3 trading budgets for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021, 2022, 2023, and 2024 are as indicated in Table 1 to this paragraph, subject to prorating for the control period in 2023 as provided in paragraph (a)(1)(ii) of this section:

TABLE 1 TO PARAGRAPH (a)(1)(i)—STATE NO_X OZONE SEASON GROUP 3 TRADING BUDGETS BY CONTROL PERIOD

[Tons]

State	2021	2022	Portion of 2023 control period before [EFFECTIVE DATE OF FINAL RULE], before prorating	Portion of 2023 control period on and after [EFFECTIVE DATE OF FINAL RULE], before prorating	2024
Alabama			13,211	6,364	6,306
Arkansas			9,210	8,889	8,889
Delaware				384	434
Illinois	11,223	9,102	8,179	7,364	7,463
Indiana	17,004	12,582	12,553	11,151	9,391
Kentucky	17,542	14,051	14,051	11,640	11,640
Louisiana	16,291	14,818	14,818	9,312	9,312
Maryland	2,397	1,266	1,266	1,187	1,187
Michigan	14,384	12,290	9,975	10,718	10,718
Minnesota				3,921	3,921
Mississippi			6,315	5,024	4,400
Missouri			15,780	11,857	11,857
Nevada				2,280	2,372
New Jersey	1,565	1,253	1,253	799	799
New York	4,079	3,416	3,421	3,763	3,763
Ohio	13,481	9,773	9,773	8,369	8,369
Oklahoma			11,641	10,265	9,573
Pennsylvania	12,071	8,373	8,373	8,855	8,855
Tennessee			7,736	4,234	4,234
Texas			52,301	38,284	38,284
Utah				14,981	15,146
Virginia	6,331	3,897	3,980	3,090	2,814
West Virginia	15,062	12,884	12,884	12,478	12,478
Wisconsin			7,915	5,963	5,057
Wyoming				9,125	8,573

(ii) For the control period in 2023, the State NO_X Ozone Season Group 3 trading budget for each State shall be calculated as the sum of the following prorated amounts, rounded to the nearest allowance:

(A) The product of the non-prorated trading budget for the portion of the 2023 control period before [EFFECTIVE DATE OF FINAL RULE] shown for the State in Table 1 to paragraph (a)(1)(i) of this section (or zero if Table 1 shows no amount for such portion of the 2023 control period for the State) multiplied by a fraction whose numerator is the number of days from May 1, 2023 through the day before [EFFECTIVE DATE OF FINAL RULE], inclusive, and whose denominator is 153; and

(B) The product of the non-prorated trading budget for the portion of the 2023 control period on and after [EFFECTIVE DATE OF FINAL RULE] shown for the State in Table 1 to paragraph (a)(1)(i) of this section multiplied by a fraction whose numerator is the number of days from [EFFECTIVE DATE OF FINAL RULE] through September 30, 2023, inclusive, and whose denominator is 153.

(2) The State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2025 and thereafter shall be the amount provided for the State and control period in the applicable notice of data availability issued under paragraph (a)(3)(v)(C) of this section.

(3) The Administrator will calculate the State NO_X Ozone Season Group 3 trading budget for each State and each control period in 2025 and thereafter in the year before the year of the control period as follows:

(i) The State's trading budget for the control period shall be calculated as the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all units identified for inclusion in the calculation under paragraph (a)(3)(ii) of this section, of the product for each such unit of the NO_X emissions rate in lb/mmBtu identified for the unit under paragraph (a)(3)(iii) of this section multiplied by the heat input in mmBtu identified for the unit under paragraph (a)(3)(iv) of this section.

(ii) A unit in a State (and Indian country within the borders of the State) shall be included in the calculation of the State's trading budget for a control period if:

(A) The unit was included in the calculation of the State's trading budget for the immediately preceding control period; or

(B) The unit's deadline for certification of monitoring systems under § 97.1030(b) is on or before May 1 of the year two years before the year of the control period (*e.g.,* May 1, 2023 for calculation of the trading budget for the control period in 2025);

(C) Provided that a unit shall not be included in the calculation of a State's trading budget for a control period if, before completing such calculation, the Administrator determines that the unit is not actually a CSAPR NO_X Ozone Season Group 3 unit.

(iii) For each unit included in the calculation of the State's trading budget for a control period, the NO_X emissions rate in lb/mmBtu used in the calculation shall be identified as follows:

(A) For a unit listed in the table entitled ''Dynamic Budget 2023 Template'' and ''Dynamic Budget 2026+ Template'' posted at *www.regulations.gov* with docket identification number EPA–HQ–OAR–2021–0668–[XXXX], the NO_X emissions rate used in the calculation for the control period shall be the NO_X emissions rate shown for the unit and control period in the tables.

(B) For a unit not listed in the table referenced in paragraph (a)(3)(iii)(A) of this section, the NO_X emissions rate used in the calculation for the control period shall be identified according to the type of unit and the type of fuel combusted by the unit during the control period beginning May 1 on or immediately after the unit's deadline for certification of monitoring systems under § 97.1030(b) as follows:

(*1*) 0.012 lb/mmBtu, for a combined cycle combustion turbine other than an integrated coal gasification combined cycle unit;

(*2*) 0.030 lb/mmBtu, for a simple cycle combustion turbine or a boiler combusting only fuel oil or gaseous fuel (other than coal-derived fuel) during such control period; or

(*3*) 0.050 lb/mmBtu, for a boiler combusting any amount of coal or coal-derived fuel during such control period or any other unit not covered by paragraph (a)(3)(iii)(B)(*1*) or (*2*) of this section.

(iv) For each unit included in the calculation of the State's trading budget for a control period, the heat input in mmBtu used in the calculation shall be identified as follows:

(A) Except as provided in paragraph (a)(3)(iv)(B) of this section, the heat input used in the calculation for the control period shall be the heat input reported for the unit for the control period in the year two years before the year of the control period (*e.g.,* heat input reported for the control period in 2023 shall be used in calculating the trading budget for the control period in 2025).

(B) If no heat input data were reported for the unit for the control period in the year two years before the year of the control period and the heat input used for the unit in calculating the State's trading budget for the control period in 2024 was an estimate rather than the unit's actual reported heat input for the control period in 2021 or an earlier year, the same estimated heat input used in calculating the State's trading budget for the control period in 2024 shall be used in the calculations of the State's trading budgets for the control periods in 2025 and 2026.

(v)(A) By March 1, 2024 and March 1 of each year thereafter, the Administrator will calculate the State CSAPR NO_X Ozone Season Group 3 trading budget for each State, in accordance with paragraph (a)(3)(i) through (iv) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(B) For each notice of data availability required in paragraph (a)(3)(v)(A) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the units included in the calculations) are in accordance with the provisions referenced in paragraph (a)(3)(v)(A) of this section.

(C) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(3)(v)(A) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(3)(v)(A) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(3)(v)(B) of this section.

(b) *New unit set-asides.* (1) The States' new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021, 2022, 2023, and 2024 are as indicated in Table 2 to this paragraph:

TABLE 2 TO PARAGRAPH (b)(1)—NEW UNIT SET-ASIDES BY CONTROL PERIOD

[Tons]

State	2021	2022	2023	2024
Alabama			191	189
Arkansas			178	178
Delaware			54	61
Illinois	265	265	368	373
Indiana	262	254	223	188
Kentucky	309	283	233	233
Louisiana	430	430	186	186
Maryland	135	115	24	24
Michigan	500	482	429	429
Minnesota			78	78
Mississippi			100	88
Missouri			237	237
Nevada			137	142
New Jersey	27	27	16	16
New York	168	168	188	188
Ohio	291	290	418	418
Oklahoma			205	191
Pennsylvania	335	339	266	266
Tennessee			85	85
Texas			766	766
Utah			449	454
Virginia	185	161	155	141
West Virginia	266	261	250	250
Wisconsin			119	101
Wyoming			274	257

(2) The new unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2025 and thereafter shall be calculated as the product (rounded to the nearest allowance) of the State NO_X Ozone Season Group 3 trading budget determined for the State and control period under paragraph (a)(2) of this section multiplied by 0.02.

(c) *Indian country new unit set-asides for the control periods in 2021 and 2022.* The States' Indian country new unit set-asides for allocations of CSAPR NO_X Ozone Season Group 3 allowances for the control periods in 2021 and 2022 are as indicated in Table 3 to this paragraph:

TABLE 3 TO PARAGRAPH (c)—INDIAN COUNTRY NEW UNIT SET-ASIDES BY CONTROL PERIOD

[Tons]

State	2021	2022
Alabama		
Arkansas		
Delaware		
Illinois		
Indiana		
Kentucky		
Louisiana	15	15
Maryland		
Michigan	13	12
Minnesota		
Mississippi		
Missouri		
Nevada		
New Jersey		
New York	3	3
Ohio		
Oklahoma		
Pennsylvania		
Tennessee		
Texas		
Utah		
Virginia		
West Virginia		
Wisconsin		
Wyoming		

(d) *Indian country existing unit set-asides for the control periods in 2023 and thereafter.* The Indian country existing unit set-aside for allocations of CSAPR NO_X Ozone Season Group 3 allowances for each State for each control period in 2023 and thereafter shall be calculated as the sum of all allowance allocations to units in areas of Indian country within the borders of the State not subject to the State's SIP authority as provided in the applicable notice of data availability for the control period referenced in § 97.1011(a)(2).

(e) *Variability limits.* (1) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period from 2021 through 2024 shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget determined for the State and control period in accordance with paragraph (a)(1) of this section multiplied by 0.21.

(2) The variability limit for the State NO_X Ozone Season Group 3 trading budget for each State for each control period in 2025 and thereafter shall be calculated as the product (rounded to the nearest ton) of the State NO_X Ozone Season Group 3 trading budget determined for the State and control period in accordance with paragraph (a)(2) of this section multiplied by the greater of:

(i) 0.21; or

(ii) Any excess over 1.00 of the quotient (rounded to two decimal places) of the total heat input reported for the control period for all CSAPR NO_X Ozone Season Group 3 units in the State and Indian country within the borders of the State divided by the total heat input used in the calculation of the State's trading budget for the control period under paragraph (a)(3) of this section.

(f) *Relationship of trading budgets, set-asides, and variability limits.* Each State NO_X Ozone Season Group 3 trading budget in this section includes any tons in a new unit set-aside, Indian country new unit set-aside, or Indian country existing unit set-aside but does not include any tons in a variability limit.

■ 74. Amend § 97.1011 by revising the section heading and paragraphs (a), (b), and (c)(1) and (5) to read as follows:

§ 97.1011 CSAPR NO_X Ozone Season Group 3 allowance allocations to existing units.

(a) *Allocations to existing units in general.* (1) For the control periods in 2021 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in each State and areas of Indian country within the borders of the State subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2025, the notices of data availability will be the notices issued under paragraph (b)(10)(iii) of this section.

(2) For the control periods in 2023 and each year thereafter, CSAPR NO_X Ozone Season Group 3 allowances will be allocated to units in areas of Indian country within the borders of each State not subject to the State's SIP authority as provided in notices of data availability issued by the Administrator. Starting with the control period in 2025, the notices of data availability will be the notices issued under paragraph (b)(10)(iii) of this section.

(3) Providing an allocation to a unit in a notice of data availability does not constitute a determination that the unit is a CSAPR NO_X Ozone Season Group 3 unit, and not providing an allocation to a unit in such notice does not constitute a determination that the unit is not a CSAPR NO_X Ozone Season Group 3 unit.

(b) *Calculation of default allocations to existing units for control periods in 2025 and thereafter.* For each control period in 2025 and thereafter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of Indian country within the borders of the State, the Administrator will calculate default allocations of CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) For each State and control period, the total amount of CSAPR NO_X Ozone Season Group 3 allowances for which default allocations will be calculated will be the remainder of the State NO_X Ozone Season Group 3 trading budget for the control period under § 97.1010(a)(2) minus the new unit set-aside for the control period under § 97.1010(b)(2).

(2) A default allocation of CSAPR NO_X Ozone Season Group 3 allowances will be calculated for a CSAPR NO_X Ozone Season Group 3 unit in the State and Indian country within the borders of the State for a control period if:

(i) The unit meets the conditions under § 97.1010(a)(3)(ii) to be included in the calculation of the State's trading budget for the control period; and

(ii) The unit reported heat input greater than zero for the control period in the year two years before the year of the control period.

(3) For each CSAPR NO_X Ozone Season Group 3 unit for which a default allocation is being calculated for a control period, the Administrator will determine the following amounts for the five-year historical period ending with the year two years before the year of the control period for which default allocations are being calculated:

(i) The total heat input reported for the unit in accordance with part 75 of this chapter for the control period in each year of the five-year historical period;

(ii) The average of the three highest of the total heat input values determined for the unit under paragraph (b)(3)(i) of this section or, if fewer than three non-zero values were determined for the unit, the average of all such non-zero heat input values;

(iii) The total NO_X emissions reported for the unit in accordance with part 75 of this chapter for the control period in each year of the five-year historical period; and

(iv) The maximum of the total NO_X emissions values determined for the unit under paragraph (b)(3)(iii) of this section.

(4) The Administrator will calculate the initial unrounded default allocations for each CSAPR NO_X Ozone Season Group 3 unit according to the procedure in paragraph (b)(5) of this section and will recalculate the unrounded default allocations according to the procedures in paragraph (b)(6) or (7) of this section, as applicable, iterating the recalculations as necessary until the total of the unrounded default allocations to all eligible units equals the amount of allowances determined for the State under paragraph (b)(1) of this section.

(5) The Administrator will calculate the initial unrounded default allocations to CSAPR NO_X Ozone Season Group 3 units as follows:

(i) The Administrator will calculate the sum, for all units determined under paragraph (b)(2) of this section to be eligible to receive a default allocation, of the units' average heat input determined under paragraph (b)(3)(ii) of this section.

(ii) For each unit determined under paragraph (b)(2) of this section to be eligible to receive a default allocation, the Administrator will calculate the unit's unrounded default allocation as the lesser of:

(A) The product of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section multiplied by a fraction whose numerator is the unit's average heat input determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(5)(i) of this section; and

(B) The unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section.

(iii) If the sum of the unrounded default allocations determined under paragraph (b)(5)(ii) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will follow the procedures in paragraph (b)(6) or (7) of this section, as applicable.

(iv) If the sum of the unrounded default allocations determined under paragraph (b)(5)(ii) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(8) and (9) of this section.

(6) If the unrounded default allocation determined in the previous round of the calculation procedure for at least one CSAPR NO_X Ozone Season Group 3 unit is less than the unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round of the calculation procedure for all units determined under paragraph (b)(2) of this section to be eligible to receive a default allocation.

(ii) The Administrator will calculate the sum, for all units whose unrounded default allocations determined in the previous round of the calculation procedure were less than the respective units' maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, of the units' average heat input determined under paragraph (b)(3)(ii) of this section.

(iii) For each unit whose unrounded default allocation determined in the previous round of the calculation was less than the unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, the Administrator will recalculate the unit's unrounded default allocation, before rounding, as the lesser of:

(A) The sum of the unit's unrounded default allocation determined in the previous round of the calculation procedure plus the product of the additional pool of allowances determined under paragraph (b)(6)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(6)(ii) of this section; and

(B) The unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section.

(iv) Except as provided in paragraph (b)(6)(iii) of this section, a unit's unrounded default allocation shall equal the amount determined in the previous round of the calculation procedure.

(v) If the sum of the unrounded default allocations determined under paragraphs (b)(6)(iii) and (iv) of this section is less than the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will iterate the procedures in paragraph (b)(6) of this section or follow the procedures in paragraph (b)(7) of this section, as applicable.

(vi) If the sum of the unrounded default allocations determined under paragraphs (b)(6)(iii) and (iv) of this section equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section, the Administrator will determine the rounded default allocations according to the procedures in paragraphs (b)(8) and (9) of this section.

(7) If the unrounded default allocation determined in the previous round of the calculation procedure for every CSAPR NO_X Ozone Season Group 3 unit equals the unit's maximum total NO_X emissions determined under paragraph (b)(3)(iv) of this section, the Administrator will recalculate the unrounded default allocations as follows:

(i) The Administrator will calculate the additional pool of allowances to be allocated as the remainder of the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section minus the sum of the unrounded default allocations from the previous round for all units determined under paragraph (b)(2) of this section to be eligible to receive a default allocation.

(ii) The Administrator will recalculate the unrounded default allocation for each eligible unit as the sum of:

(A) The unit's unrounded default allocation as determined in the previous round of the calculation procedure; plus

(B) The product of the additional pool of allowances determined under paragraph (b)(7)(i) of this section multiplied by a fraction whose numerator is the unit's average heat input determined under paragraph (b)(3)(ii) of this section and whose denominator is the sum determined under paragraph (b)(5)(i) of this section.

(8) The Administrator will round the default allocation for each eligible unit determined under paragraph (b)(5), (6), or (7) of this section to the nearest allowance and make any adjustments required under paragraph (b)(9) of this section.

(9) If the sum of the default allocations after rounding under paragraph (b)(8) of this section does not equal the total amount of allowances determined for the State and control period under paragraph (b)(1) of this

section, the Administrator will adjust the default allocations as follows. The Administrator will list the CSAPR NO_X Ozone Season Group 3 units in descending order based on such units' allocation amounts under paragraph (b)(8) of this section and, in cases of equal allocation amounts, in alphabetical order of the relevant sources' names and numerical order of the relevant units' identification numbers, and will adjust each unit's allocation amount upward or downward by one CSAPR NO_X Ozone Season Group 3 allowance (but not below zero) in the order in which the units are listed, and will repeat this adjustment process as necessary, until the total of the adjusted default allocations equals the total amount of allowances determined for the State and control period under paragraph (b)(1) of this section.

(10)(i) By March 1, 2024 and March 1 of each year thereafter, the Administrator will calculate the default allocation of CSAPR NO_X Ozone Season Group 3 allowances to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State, in accordance with paragraphs (b)(1) through (9) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year after the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(10)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice of data availability and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(10)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(10)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(10)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(10)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to existing units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period to a recipient covered by the provisions of paragraph (c)(1)(i), (ii), or (iii) of this section, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section:

(i) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under paragraph (a)(1) or (2) of this section;

(ii) The recipient is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of the control period and is allocated CSAPR NO_X Ozone Season Group 3 allowances for such control period under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter that the SIP revision provides should be allocated only to recipients that are CSAPR NO_X Ozone Season Group 3 units as of the first day of such control period; or

(iii) The recipient is not located as of the first day of the control period in the State (and Indian country within the borders of the State) from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances allocated under paragraph (a)(1) or (2) of this section, or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter, were allocated for such control period.

* * * * *

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for 2021, 2022, or 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024 and on or before May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for such control period for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024 and after May 1 of the year following the year of the control period for which the CSAPR NO_X Ozone Season Group 3 allowances were allocated, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 75. Amend § 97.1012 by:
■ a. Revising paragraphs (a) introductory text and (a)(1)(i) and (ii);
■ b. Removing paragraphs (a)(1)(iii) and (iv);
■ c. Revising paragraphs (a)(2) and (a)(3)(i);
■ d. In paragraph (a)(3)(ii), adding ''and'' after the semicolon;
■ e. Revising paragraph (a)(3)(iii);
■ f. Removing paragraph (a)(3)(iv);
■ g. Revising paragraphs (a)(5) and (10):
■ h. In paragraph (a)(11), removing ''§ 97.1011(b)(1)(i), (ii), and (v), of'' and adding in its place ''paragraph (a)(13) of this section, of'';
■ i. Adding paragraph (a)(13);
■ j. Revising paragraphs (b) introductory text and (b)(1) and (2);
■ k. In paragraph (b)(5), removing ''Indian country within the borders of the State'' and adding in its place ''areas of Indian country within the borders of the State not subject to the State's SIP authority'';
■ l. Revising paragraph (b)(10);
■ m. In paragraph (b)(11), removing ''§ 97.1011(b)(2)(i), (ii), and (v), of'' and adding in its place ''paragraph (b)(13) of this section, of''; and
■ n. Adding paragraphs (b)(13) and (c).

The revisions and additions read as follows:

§ 97.1012 CSAPR NO_X Ozone Season Group 3 allowance allocations to new units.

(a) *Allocations from new unit set-asides.* For each control period in 2021 and thereafter for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or 2023 and thereafter for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter, and for the CSAPR NO_X Ozone Season Group 3 units in each State and areas of

Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority), the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) * * *

(i) CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period; or

(ii) CSAPR NO_X Ozone Season Group 3 units whose allocation of an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2) is covered by § 97.1011(c)(2) or (3).

(2) The Administrator will establish a separate new unit set-aside for the State for each such control period. Each such new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(b) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with § 97.1011(c)(5) and paragraphs (b)(10) and (c)(5) of this section.

(3) * * *

(i) The control period in 2021, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, or the control period in 2023, for a State listed in § 52.38(b)(2)(iii)(B) or (C) of this chapter;

* * * * *

(iii) For a unit described in paragraph (a)(1)(ii) of this section, the first control period in which the CSAPR NO_X Ozone Season Group 3 unit operates in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) after operating in another jurisdiction and for which the unit is not already allocated one or more CSAPR NO_X Ozone Season Group 3 allowances.

* * * * *

(5) The Administrator will calculate the sum of the allocation amounts of CSAPR NO_X Ozone Season Group 3 allowances determined for all such CSAPR NO_X Ozone Season Group 3 units under paragraph (a)(4)(i) of this section in the State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the borders of the State not subject to the State's SIP authority) for such control period.

* * * * *

(10)(i) For a control period in 2021 or 2022, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period in the applicable notice of data availability referenced in § 97.1011(a)(1) an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the sum of the amounts of tons in such new unit set-aside and the Indian country new unit set-aside for the State for such control period, and rounded to the nearest allowance.

(ii) For a control period in 2023 or thereafter, if, after completion of the procedures under paragraphs (a)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the new unit set-aside for the State for such control period, the Administrator will allocate to each CSAPR NO_X Ozone Season Group 3 unit that is in the State and Indian country within the borders of the State and is allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for the control period by the Administrator in the applicable notice of data availability referenced in § 97.1011(a)(1) or (2), or under a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter, an amount of CSAPR NO_X Ozone Season Group 3 allowances equal to the following: The total amount of such remaining unallocated CSAPR NO_X Ozone Season Group 3 allowances in such new unit set-aside, multiplied by the unit's allocation under § 97.1011(a)(1) or (2) or a provision of a SIP revision approved under § 52.38(b)(10), (11), or (12) of this chapter for such control period, divided by the remainder of the amount of tons in the applicable State NO_X Ozone Season Group 3 trading budget minus the amount of tons in such new unit set-aside for the State for such control period, and rounded to the nearest allowance.

* * * * *

(13)(i) By March 1, 2022 and March 1 of each year thereafter, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in a State and Indian country within the borders of the State (except, for the control periods in 2021 and 2022, areas of Indian country within the State not subject to the State's SIP authority), in accordance with paragraphs (a)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (a)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (a)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (a)(13)(ii) of this section.

(b) *Allocations from Indian country new unit set-asides.* For the control periods in 2021 and 2022, for a State listed in § 52.38(b)(2)(iii)(A) of this chapter, and for the CSAPR NO_X Ozone

Season Group 3 units in areas of Indian country within the borders of each such State not subject to the State's SIP authority, the Administrator will allocate CSAPR NO_X Ozone Season Group 3 allowances to the CSAPR NO_X Ozone Season Group 3 units as follows:

(1) The CSAPR NO_X Ozone Season Group 3 allowances will be allocated to CSAPR NO_X Ozone Season Group 3 units that are not allocated an amount of CSAPR NO_X Ozone Season Group 3 allowances for such control period in the applicable notice of data availability issued under § 97.1011(a)(1) and that have deadlines for certification of monitoring systems under § 97.1030(b) not later than September 30 of the year of the control period, except as provided in paragraph (b)(10) of this section.

(2) The Administrator will establish a separate Indian country new unit set-aside for the State for each such control period. Each such Indian country new unit set-aside will be allocated CSAPR NO_X Ozone Season Group 3 allowances in an amount equal to the applicable amount of tons of NO_X emissions as set forth in § 97.1010(c) and will be allocated additional CSAPR NO_X Ozone Season Group 3 allowances (if any) in accordance with paragraph (c)(5) of this section.

* * * * *

(10) If, after completion of the procedures under paragraphs (b)(2) through (7) and (12) of this section for a control period, any unallocated CSAPR NO_X Ozone Season Group 3 allowances remain in the Indian country new unit set-aside for the State for such control period, the Administrator will transfer such unallocated CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the State for such control period.

* * * * *

(13)(i) By March 1, 2022 and March 1, 2023, the Administrator will calculate the CSAPR NO_X Ozone Season Group 3 allowance allocation to each CSAPR NO_X Ozone Season Group 3 unit in areas of Indian country within the borders of a State not subject to the State's SIP authority, in accordance with paragraphs (b)(2) through (7), (10), and (12) of this section and §§ 97.1006(b)(2) and 97.1030 through 97.1035, for the control period in the year before the year of the applicable calculation deadline under this paragraph and will promulgate a notice of data availability of the results of the calculations.

(ii) For each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will provide an opportunity for submission of objections to the calculations referenced in such notice. Objections shall be submitted by the deadline specified in such notice and shall be limited to addressing whether the calculations (including the identification of the CSAPR NO_X Ozone Season Group 3 units) are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section.

(iii) The Administrator will adjust the calculations to the extent necessary to ensure that they are in accordance with the provisions referenced in paragraph (b)(13)(i) of this section. By May 1 immediately after the promulgation of each notice of data availability required in paragraph (b)(13)(i) of this section, the Administrator will promulgate a notice of data availability of the results of the calculations incorporating any adjustments that the Administrator determines to be necessary and the reasons for accepting or rejecting any objections submitted in accordance with paragraph (b)(13)(ii) of this section.

(c) *Incorrect allocations of CSAPR NO_X Ozone Season Group 3 allowances to new units.* (1) For each control period in 2021 and thereafter, if the Administrator determines that CSAPR NO_X Ozone Season Group 3 allowances were allocated for the control period under paragraphs (a)(2) through (7) and (12) of this section or paragraphs (b)(2) through (7) and (12) of this section to a recipient that is not actually a CSAPR NO_X Ozone Season Group 3 unit under § 97.1004 as of the first day of such control period, then the Administrator will notify the designated representative of the recipient and will act in accordance with the procedures set forth in paragraphs (c)(2) through (5) of this section.

(2) Except as provided in paragraph (c)(3) or (4) of this section, the Administrator will not record such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021.

(3) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section before making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will deduct from the account in which such CSAPR NO_X Ozone Season Group 3 allowances were recorded an amount of CSAPR NO_X Ozone Season Group 3 allowances allocated for the same or a prior control period equal to the amount of such already recorded CSAPR NO_X Ozone Season Group 3 allowances. The authorized account representative shall ensure that there are sufficient CSAPR NO_X Ozone Season Group 3 allowances in such account for completion of the deduction.

(4) If the Administrator already recorded such CSAPR NO_X Ozone Season Group 3 allowances under § 97.1021 and if the Administrator makes the determination under paragraph (c)(1) of this section after making deductions for the source that includes such recipient under § 97.1024(b) for such control period, then the Administrator will not make any deduction to take account of such already recorded CSAPR NO_X Ozone Season Group 3 allowances.

(5) With regard to any CSAPR NO_X Ozone Season Group 3 allowances that are not recorded, or that are deducted as an incorrect allocation, in accordance with paragraphs (c)(2) and (3) of this section:

(i) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs on or before May 1, 2023, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside, in the case of allowances allocated under paragraph (a) of this section, or the Indian country new unit set-aside, in the case of allowances allocated under paragraph (b) of this section, for the control period in 2021 or 2022 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(ii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2023 and on or before May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to the new unit set-aside for the control period in 2023 for the State from whose NO_X Ozone Season Group 3 trading budget the CSAPR NO_X Ozone Season Group 3 allowances were allocated.

(iii) If the non-recordation decision under paragraph (c)(2) of this section or the deduction under paragraph (c)(3) of this section occurs after May 1, 2024, the Administrator will transfer the CSAPR NO_X Ozone Season Group 3 allowances to a surrender account.

■ 76. Amend § 97.1021 by:

■ a. In paragraph (a), removing "§ 97.1011(a)" and adding in its place "§ 97.1011(a)(1)";

■ b. Revising paragraph (b);

■ c. Removing and reserving paragraph (c);

■ d. Revising paragraph (d);

■ e. Adding paragraph (e);

■ f. Revising paragraphs (f) and (g);

■ g. In paragraph (h), removing ''May 1 of each year thereafter, the'' and adding in its place ''May 1, 2023, the'';
■ h. Adding paragraphs (i) and (j); and
■ i. In paragraph (m), adding ''or (e)'' after ''§ 97.811(d)'' each time it appears.

The revisions and addition read as follows:

§ 97.1021 Recordation of CSAPR NO_X Ozone Season Group 3 allowance allocations and auction results.

* * * * *

(b) By July 29, 2021, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2022.

* * * * *

(d) By [30 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2023.

(e) By [30 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024, unless the State in which the source is located notifies the Administrator in writing by [EFFECTIVE DATE OF FINAL RULE] of the State's intent to submit to the Administrator a complete SIP revision by September 1, 2023 meeting the requirements of § 52.38(b)(10)(i) through (iv) of this chapter.

(1) If, by September 1, 2023 the State does not submit to the Administrator such complete SIP revision, the Administrator will record by September 15, 2023 in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

(2) If the State submits to the Administrator by September 1, 2023 and the Administrator approves by March 1, 2024 such complete SIP revision, the Administrator will record by March 1, 2024 in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source as provided in such approved, complete SIP revision for the control period in 2024.

(3) If the State submits to the Administrator by September 1, 2023 and the Administrator does not approve by March 1, 2024 such complete SIP revision, the Administrator will record by March 1, 2024 in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(1) for the control period in 2024.

(f) By July 1, 2024 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source, or in each appropriate Allowance Management System account the CSAPR NO_X Ozone Season Group 3 allowances auctioned to CSAPR NO_X Ozone Season Group 3 units, in accordance with § 97.1011(a)(1), or with a SIP revision approved under § 52.38(b)(11) or (12) of this chapter, for the control period in the year after the year of the applicable recordation deadline under this paragraph.

(g) By May 1, 2022 and May 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1012(a) for the control period in the year before the year of the applicable recordation deadline under this paragraph.

* * * * *

(i) By [30 DAYS AFTER EFFECTIVE DATE OF FINAL RULE], the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control periods in 2023 and 2024.

(j) By July 1, 2024 and July 1 of each year thereafter, the Administrator will record in each CSAPR NO_X Ozone Season Group 3 source's compliance account the CSAPR NO_X Ozone Season Group 3 allowances allocated to the CSAPR NO_X Ozone Season Group 3 units at the source in accordance with § 97.1011(a)(2) for the control period in the year after the year of the applicable recordation deadline under this paragraph.

* * * * *

■ 77. Amend § 97.1024 by:
■ a. Revising the section heading;
■ b. In paragraphs (a) introductory text and (b) introductory text, adding ''primary'' before ''emissions limitation'';
■ c. Revising paragraph (b)(1);
■ d. Adding paragraph (b)(3); and
■ e. In paragraph (c)(2)(ii), adding ''or (e)'' after ''§ 97.826(d)''.

The revisions and addition read as follows:

§ 97.1024 Compliance with CSAPR NO_X Ozone Season Group 3 primary emissions limitation.

* * * * *

(b) * * *

(1) Until the amount of CSAPR NO_X Ozone Season Group 3 allowances deducted equals the sum of:

(i) The number of tons of total NO_X emissions from all CSAPR NO_X Ozone Season Group 3 units at the source for such control period; plus

(ii) Two times the sum (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton), for all days in the control period and all CSAPR NO_X Ozone Season Group 3 units at the source to which backstop daily NO_X emissions rates apply for the control period under paragraph (b)(3) of this section, of any amount by which a unit's NO_X emissions for a given day in pounds exceed the product in pounds of the unit's total heat input in mmBtu for that day multiplied by the applicable backstop daily NO_X emissions rate in lb/mmBtu; or

* * * * *

(3) The applicable backstop daily NO_X emissions rates are as follows:

(i) For the control periods in 2024 and each year thereafter, a backstop daily NO_X emissions rate of 0.14 lb/mmBtu shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal during the control period, serving a generator with nameplate capacity of 100 MW or more, and equipped with selective catalytic reduction controls, except a circulating fluidized bed boiler.

(ii) For the control periods in 2027 and each year thereafter, a backstop daily NO_X emissions rate of 0.14 lb/mmBtu shall apply to each CSAPR NO_X Ozone Season Group 3 unit combusting any coal during the control period and serving a generator with nameplate capacity of 100 MW or more, except a circulating fluidized bed boiler.

* * * * *

■ 78. Amend § 97.1025 by revising the section heading and adding paragraph (c) to read as follows:

§ 97.1025 Compliance with CSAPR NO_X Ozone Season Group 3 assurance provisions; CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.

* * * * *

(c) *CSAPR NO_X Ozone Season Group 3 secondary emissions limitation.* (1) The owner or operator of a base CSAPR NO_X Ozone Season Group 3 unit shall not discharge, or allow to be discharged, emissions of NO_X to the atmosphere during a control period in excess of the tonnage amount calculated in accordance with paragraph (c)(2) of this section, provided that the emissions limitation established under this paragraph shall apply to a unit for a control period only if:

(i) The unit is included for the control period in a group of base CSAPR NO_X Ozone Season Group 3 units at base CSAPR NO_X Ozone Season Group 3 sources in a State (and Indian country within the borders of such State) having a common designated representative and the owners and operators of such units and sources are subject to a requirement for such control period to hold one or more CSAPR NO_X Ozone Season Group 3 allowances under § 97.1006(c)(2)(i) and paragraph (b) of this section with respect to such group; and

(ii) The unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours during the control period and all or portions of at least 367 operating hours during at least one previous control period under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program.

(2) The amount of the emissions limitation applicable to a base CSAPR NO_X Ozone Season Group 3 unit for a control period under paragraph (c)(1) of this section, in tons of NO_X, shall be calculated as the sum of 50 plus the product (converted to tons at a conversion factor of 2,000 lb/ton and rounded to the nearest ton) of multiplying—

(i) The total heat input in mmBtu reported for the unit for the control period in accordance with §§ 97.1030 through 97.1035; and

(ii) A NO_X emission rate of 0.10 lb/mmBtu or, if higher, the product of 1.25 times the lowest seasonal average NO_X emission rate in lb/mmBtu achieved by the unit in any previous control period for which the unit was required to report NO_X emissions and heat input data for all or portions of at least 367 operating hours under the CSAPR NO_X Ozone Season Group 1 Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, or CSAPR NO_X Ozone Season Group 3 Trading Program, where the unit's seasonal average NO_X emission rate for each such previous control period shall be calculated from such reported data as the quotient of the unit's total NO_X emissions in tons for the control period divided by the unit's total heat input in mmBtu for the control period, multiplied by a conversion factor of 2,000 lb/ton, and rounded to the nearest 0.0001 lb/mmBtu.

■ 79. Amend § 97.1026 by:

■ a. Revising paragraph (b);

■ b. In paragraph (c), removing ''State (or Indian'' and adding in its place ''State (and Indian''; and

■ c. Adding paragraph (d).

The revision and addition read as follows:

§ 97.1026 Banking.

* * * * *

(b) Any CSAPR NO_X Ozone Season Group 3 allowance that is held in a compliance account or a general account will remain in such account unless and until the CSAPR NO_X Ozone Season Group 3 allowance is deducted or transferred under § 97.1011(c), § 97.1012(c), § 97.1023, § 97.1024, § 97.1025, § 97.1027, or § 97.1028 or paragraph (c) or (d) of this section.

* * * * *

(d) Before the allowance transfer deadline for each control period in 2024 or a subsequent year, the Administrator will deduct amounts of CSAPR NO_X Ozone Season Group 3 allowances issued for the control periods in previous years exceeding the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in accordance with paragraphs (d)(1) through (4) of this section.

(1) As soon as practicable on or after August 1, 2024 and August 1 of each subsequent year, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 3 allowance transfers submitted under § 97.1022 and, before resuming acceptance of such transfers, will take the actions in paragraphs (d)(2) through (4) of this section.

(2) The Administrator will determine each of the following values:

(i) The CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period in the year of the deadline under paragraph (d)(1) of this section, calculated as the product, rounded to the nearest allowance, of 0.105 times the sum for all States listed in § 52.38(b)(2)(iii) of this chapter of the State NO_X Ozone Season Group 3 trading budgets under § 97.1010(a) for such States for such control period.

(ii) The total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in all compliance and general accounts.

(3) If the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(i) of this section is less than the total amount of CSAPR NO_X Ozone Season Group 3 allowances determined under paragraph (d)(2)(ii) of this section, then for each compliance account or general account holding CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section, the Administrator will:

(i) Determine the total amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section and held in the account.

(ii) Determine the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period, calculated as the product, rounded up to the nearest allowance, of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target determined under paragraph (d)(2)(i) of this section multiplied by a fraction whose numerator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section and whose denominator is the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in all compliance and general accounts determined under paragraph (d)(2)(ii) of this section.

(iii) Deduct an amount of CSAPR NO_X Ozone Season Group 3 allowances issued for control periods in years before the year of the deadline under paragraph (d)(1) of this section equal to any positive remainder of the total amount of CSAPR NO_X Ozone Season Group 3 allowances held in the account determined under paragraph (d)(3)(i) of this section minus the account's share of the CSAPR NO_X Ozone Season Group 3 allowance bank ceiling target for the control period determined under paragraph (d)(3)(ii) of this section. The allowances will be deducted on a first-in, first-out basis in the order set forth in § 97.1024(c)(2)(i) and (ii).

(iv) Record the deductions under paragraph (d)(3)(iii) of this section in the account.

(4)(i) In computing any amounts of CSAPR NO_X Ozone Season Group 3 allowances to be deducted from general accounts under paragraph (d)(3) of this section, the Administrator may group multiple general accounts whose ownership interests are held by the same or related persons or entities and treat the group of accounts as a single account for purposes of such computation.

(ii) Following a computation for a group of general accounts in accordance with paragraph (d)(4)(i) of this section, the Administrator will deduct from and record in each individual account in such group a proportional share of the quantity of CSAPR NO_X Ozone Season Group 3 allowances computed for such group, basing such shares on the respective quantities of CSAPR NO_X Ozone Season Group 3 allowances determined for such individual accounts under paragraph (d)(3)(i) of this section.

(iii) In determining the proportional shares under paragraph (d)(4)(ii) of this section, the Administrator may employ any reasonable adjustment methodology to truncate or round each such share up or down to a whole number and to cause the total of such whole numbers to equal the amount of CSAPR NO_X Ozone Season Group 3 allowances computed for such group of accounts in accordance with paragraph (d)(4)(i) of this section, even where such adjustments cause the numbers of CSAPR NO_X Ozone Season Group 3 allowances remaining in some individual accounts following the deductions to equal zero.

■ 80. Amend § 97.1030 by:

■ a. Revising paragraph (b)(1); and

■ b. In paragraph (b)(3), removing ''(b)(2)'' and adding in its place ''(b)(1) or (2)''.

The revision reads as follows:

§ 97.1030 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) * * *

(1)(i) May 1, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(ii) May 1, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter;

(iii) [EFFECTIVE DATE OF FINAL RULE], for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements; or

(iv) [180 DAYS AFTER EFFECTIVE DATE OF FINAL RULE] for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter, where the unit is not required to report NO_X mass emissions data or NO_X emissions rate data according to 40 CFR part 75 to address other regulatory requirements.

* * * * *

■ 81. Amend § 97.1034 by:

■ a. Revising paragraph (d)(2)(i); and

■ b. In paragraph (d)(4), removing ''or CSAPR SO_2 Group 1 Trading Program, quarterly'' and adding in its place ''CSAPR SO_2 Group 1 Trading Program, or CSAPR SO_2 Group 2 Trading Program, quarterly''.

The revision reads as follows:

§ 97.1034 Recordkeeping and reporting.

* * * * *

(d) * * *

(2) * * *

(i)(A) The calendar quarter covering May 1, 2021 through June 30, 2021, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(A) of this chapter;

(B) The calendar quarter covering May 1, 2023 through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(B) of this chapter; or

(C) The calendar quarter covering [EFFECTIVE DATE OF FINAL RULE] through June 30, 2023, for a unit in a State (and Indian country within the borders of such State) listed in § 52.38(b)(2)(iii)(C) of this chapter;

* * * * *

[FR Doc. 2022–04551 Filed 3–30–22; 4:15 pm]

BILLING CODE 6560–50–P

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit D

United States Steel Corporation Comments on Proposed Federal Implementation Plan, EPA-HQ-OAR-2021-0668-0798 (June 21, 2022)

UNITED STATES STEEL CORPORATION
COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN ADDRESSING REGIONAL OZONE TRANSPORT FOR THE 2015 8-HOUR NAAQS.

Docket ID No. EPA-HQ-OAR-2021-0668

87 Federal Register 20,036 (April 6, 2022)

JUNE 21, 2022

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USS SIP Disapproval Comment

Exhibit F:

USS FIP Comment Extension

United States Steel Corporation Law Department
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June 21, 2022

ATTN: Docket ID No. EPA-HQ-OAR-2021-0668

Administrator Michael Regan
C/O EPA Docket Center (EPA/DC)
Docket ID No. EPA-HQ-OAR-2021-0668
U.S. Environmental Protection Agency

Submitted via Federal eRulemaking Portal (Regulations.gov)

RE: Comments of United States Steel Corporation ("U. S. Steel") on the "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard," Docket No. EPA-HQ-OAR-2021-0668, 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule").

Dear Administrator Regan,

United States Steel Corporation ("U. S. Steel") on behalf of the company and all our subsidiaries[1] and affiliates appreciates the opportunity to submit the following comments to the United States Environmental Protection Agency ("EPA") regarding the proposed "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard" Docket No. EPA-HQ-OAR-2021-0668. *Federal Register* 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule"). The Proposed Rule creates Ozone NOx Standards related to the Clean Air Act Good Neighbor provisions. The comment period for the Notice closes on June 21, 2022. U.S. Steel provides the following general and specific comments below related to the Proposed Rule.

[1] Big River Steel, LLC (BRS) and Exploratory Ventures, LLC (EV) are both wholly owned subsidiaries of U. S. Steel. BRS is an operating scrap to steel products facility in Osceola, Arkansas and EV is a scrap to steel products facility under construction in Osceola, Arkansas. These are only two of the U. S. Steel subsidiaries and facilities and these comments apply to all subsidiaries and locations however some comments may directly reference these locations.

INTRODUCTION

The Proposed Rule's treatment of non-EGUs, including the iron and steel industry, sharply departs from EPA practice and court interpretations of the Good Neighbor provision of the Clean Air Act (CAA). As more fully detailed herein, EPA treats EGUs and non-EGU sources (including the iron and steel industry) in fundamentally different ways, many of which directly conflict with past EPA determinations and court decisions without reasonable explanations for departure, including but not limited to:

- Setting statewide budget limits for EGUs, while instead subjecting iron and steel units to unit specific command and control limits without any evaluation of how the proposed limits relate to the amount of statewide reductions needed to eliminate a state's alleged substantial contribution;
- Allowing emissions trading for EGUs, but not for non-EGUs;
- Accounting for feasibility in evaluating applicability of EGU provisions to types of EGUs (e.g., waste incinerators) and which States to subject to the EGU provisions (e.g., California), but not performing any feasibility analysis, much less facility or unit specific feasibility analysis, for the iron and steel industry (indeed, ignoring all prior determinations, including recent determinations that post combustion controls[2] are not feasible for EAFs and other emission units the Proposed Rule would cover in the iron and steel industry);
- Modeling impacts and cost effectiveness of controls for EGUs as a single industry, but grouping all other covered industries together as "non-EGUs" for a single cost effectiveness analysis, without evaluating what level of controls would be cost effective for each of the separate industries the Proposed Rule would cover;
- Modeling the effect of multiple cost thresholds for EGUs as an industry ($1,600, $1,800, and $11,000) to evaluate whether lower cost thresholds could achieve sufficient reductions, but only modeling a single cost threshold ($7,500) for all non-EGUs without any consideration of whether a lower cost threshold for some or all such industries could still result in sufficient emission reductions to satisfy Good Neighbor requirements.

When determining what non-EGUs to regulate under the Proposed Rule, EPA also did not correctly follow the "4-step interstate transport framework" used by EPA in prior rulemakings and approved by the Supreme Court. Under that approach, EPA, after identifying nonattainment and maintenance receptors (step 1), and screening out any state not significantly contributing to any linked receptor (step 2), was then supposed to "(3) for states linked to downwind air quality

[2] The term "post-combustion controls" is used herein only for convenience and consistency with the way in which EPA describes emission controls such as SCR in the Proposed Rule. As described in more detail herein, some of the furnaces covered by the Proposed Rule, most notably an EAF, is not a combustion process, such that any downstream emission controls on an EAF would not technically be "post-combustion."

problems, identify [] upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implement[] the necessary emissions reductions through enforceable measures." But the EPA did not follow this approach in the Proposed Rule. Rather than evaluate the upwind emissions that actually contribute to each screened-in state's linked nonattainment or maintenance receptors, EPA instead just (1) identified industries nationwide that contributed relatively more than other industries, and (2) automatically mandated limits directly on all such industries in each screened-in state, skipping any finding that the industries (let alone specific sources) evaluated on a nationwide basis actually contributed to nonattainment or interfered in maintenance at the linked receptors for each particular state.

The resulting Proposed Rule imposes limits on NOx emissions that EPA's own analysis acknowledges have never been demonstrated in the iron and steel industry and cannot be met by any technology currently available for use in the iron and steel industry. Many of the technologies proposed by EPA to control NOx (e.g., SCR, SNCR) are not technically feasible for the emission units included under the Proposed Rule. And even if technology used in wholly dissimilar industrial processes (e.g. coal-fired power plants and boilers) were able to be implemented, the costs would be significantly higher than the thresholds EPA relied upon for screening out available control technologies. EPA also assumes that low NOx burners are an available technology for certain emission units to reduce NOx emissions, completely ignoring the fact that many of these units already incorporate low NOx burner technology. Associated production downtimes also would have severe economic consequences for the industry. Furthermore, it is without question that efforts to adapt these technologies to the iron and steel industry would increase emissions of other pollutants and require re-engineering and modifications to not only the steel making process, but also existing air pollution control equipment. Simply put, the addition of ancillary equipment to address flue gas characteristics and the batch nature of the steelmaking process, among other challenges, would necessarily drive up costs and have both upstream and downstream impacts that would not have been accounted for in the original equipment design specifications.

The Proposed Rule also makes assumptions regarding equipment availability and constructability that cannot be reconciled with present and future supply chain considerations and threatens to hamstring the economy and national security with extended downtime or closures and resultant shortages of domestic iron and steel supply.

To justify all the above, the Proposed Rule relies on arbitrary modeling using result-oriented assumptions containing significant errors and omissions, incorrect interpretations of the CAA and legal precedents addressing pollution transport. In short, the Proposed Rule attempts to go well beyond EPA's authority under the CAA. In so doing EPA risks legal challenges to any final rule in the same form as the Proposed Rule that will restrict EPA's discretion in future rulemakings. And because the Supreme Court allows as applied challenges to rulemakings effectuating the Good Neighbor clause of the CAA, EPA's decision to make the Proposed Rule apply on a unit specific basis directly to facilities means that EPA will open the door to as-applied challenges as every covered facility will have the ability to challenge the applicability of the Proposed Rule's limits as applied to that facility, likely jettisoning the uniformity that EPA purports to seek in the Proposed Rule and stringing out any rulemaking in constant challenges.

GENERAL COMMENTS PERTAINING TO THE PROPOSED RULE

I. The Proposed Rule's Attempt to Impose Unit Specific Emission Limits Is Unlawful, Arbitrary, and Not Supported By the Record.

A. EPA Has Identified No Legal Basis for Imposing Emission Unit Specific Limits on Any of the Individual Non-EGU Emission Units the Proposed Rule Purports to Regulate.

The provision of the CAA on which EPA bases this entire regulatory undertaking (a/k/a the "Good Neighbor provision" to the CAA) only grants authority to:

> "prohibit[ ] . . . any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard"[3]

Thus, when enacting a FIP to satisfy this provision, EPA only has authority to regulate a "source" or "type of emissions activity" if EPA demonstrates that the specific "source" or "type of emissions activity" it proposes to subject to such regulation is actually contributing significantly to nonattainment or interference with maintenance status in a state other than that in which the "source" or "type of emissions activity" is located.

This is the first time EPA has attempted to impose facility-specific emission limits under a "one-size fits all" Federal Implementation Plan based upon the Good Neighbor provision of the CAA. Accordingly, for EPA to have authority to do so under the Good Neighbor provision, EPA must demonstrate that the "source" EPA is prohibiting from emitting above the Proposed Rule's NOx limits is contributing significantly to downwind nonattainment or contributing significantly to downwind maintenance issues. But EPA fails to provide any basis for finding any U. S. Steel facility to contribute significantly to any nonattainment or interference with maintenance.

First, EPA does not define any threshold to evaluate whether a given source's contribution constitutes a significant contribution to downwind linked receptors for purposes of the Good Neighbor provision.[4] Instead, EPA sweeps in states based on a statewide significance threshold of 0.7ppb, identifies industries that on a nationwide basis contribute to downwind nonattainment or

[3] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

[4] As discussed in more detail in another comment below, EPA has in fact established a facility specific significance threshold of 1ppb (i.e., the Ozone SIL) based on an actual statistical analysis of what contribution is capable of showing any modeled effect beyond mere background variation, but the Proposed Rule at no point acknowledges this threshold or prior statistical analysis.

maintenance receptors using a 0.01ppb significance threshold[5], then skips to applying the Proposed Rule's limits to all facilities in all such industries in all covered states without any evaluation of the statutory mandate to consider whether the specific covered "source or other type of emissions activity" will "contribute significantly to nonattainment." Failure to even set a threshold to evaluate source-level contribution significance constitutes a failure to attempt the evaluation required under the statute if EPA wishes to set source-specific emission limits.

Second, the Proposed Rule neglects to perform any source-specific impact analysis to evaluate the impact (or lack thereof) that the specific sources EPA proposes to subject to NOx limits have on any of the identified nonattainment and maintenance receptors. And this failure is not for lack of capacity. The CAMx model EPA relied on for evaluating nonattainment and maintenance receptors has the capability to tag source-level and/or industry-level contributions. As EPA notes, CAMx "employs enhanced source apportionment techniques that track the formation and transport of ozone from specific emissions sources and calculates the contribution of sources and precursors to ozone for individual receptor locations."[6] But the Proposed Rule acknowledges that EPA ignored facility level impacts on downwind-state ozone concentrations, and instead, when using CAMx, only "performed nationwide, state level ozone source apportionment modeling."[7] This failure to evaluate the significance of source specific impacts means that EPA has failed to demonstrate that U. S. Steel facilities it proposes to regulate are in fact linked to any nonattainment or maintenance receptor so as to permit emission reductions under the Good Neighbor provision of the CAA.

To be sure, EPA has not always evaluated source specific impacts on downwind receptors in other states in its prior rulemakings, but that is because those prior rulemakings were fundamentally different than the Proposed Rule. For instance, under the ozone transport rule evaluated by the Supreme Court in *EPA v. EME Homer City Generation, L.P.* 572 U.S. 489 (2014), EPA did not attempt to impose source specific controls or emission limits, but instead created an annual emission "budget" for each state that EPA concluded was contributing significantly to downwind nonattainment and maintenance issues, and then set up an interstate emission trading system within such state allowing covered sources to allocate the emissions and any needed reductions among themselves through purchase and sale of allowances.[8] Under a regulatory program set up in that manner, it may have been rational to impose an aggregated statewide emission limit for NOx from EGUs based on similarities in the sources and a finding at the same

[5] See e.g., Proposed Rule at 20,083 n. 164 (screening the significance of industry contributions using either 0.1ppb at at least one nonattainment or maintenance receptor, or 0.01ppb at at least ten such receptors, but nowhere setting a facility specific significance screening threshold).

[6] Proposed rule at 20,070.

[7] Proposed rule at 20,070.

[8] See 76 Fed. Reg. 48,208; see also EPA, "Fact Sheet: The Cross-State Air Pollution Rule: Reducing the Interstate Transport of Fine Particulate Matter and Ozone" available at https://www.epa.gov/sites/default/files/2016-09/documents/csaprfactsheet.pdf ("The final Cross-State Air Pollution Rule allows sources to trade emissions allowances with other sources within the same program (e.g., ozone season NOX) in the same or different states, while firmly constraining any emissions shifting that may occur by requiring a strict emission ceiling in each state").

level of generality that a state's statewide emissions in the aggregate significantly contributed to downwind nonattainment, and that EGUs were the primary driver (i.e., treating statewide EGU emissions as the "emissions activity" which EPA could "prohibit . . . amounts which will . . . contribute significantly to nonattainment").

Instead, EPA proposes for the first time to use the Good Neighbor provision to impose command-and-control limits at the individual facility level without any justification that the facility (or even the industrial section in the state that it is part of) contributes significantly to downstream nonattainment or maintenance issues. It is one thing for EPA to tell a state that its contribution to nonattainment/maintenance problems in another state is a certain level and then allow a state or the sources therein to allocate reductions needed among themselves to achieve the statewide reductions needed; it is quite another thing to impose specific emission limits directly on a state's sources without any further source level analysis. If EPA wishes to treat individual emission units as the granular level of "source or other emissions activity" from which to "prohibit . . . amounts which will . . . contribute significantly to nonattainment," it must necessarily show that such units "contribute significantly to nonattainment." And EPA has not attempted to do so with respect to any of the non-EGU emission units in the Proposed Rule, let alone for the emission units at U. S. Steel facilities.

B. The Analyses Included in the Record Cannot Support the Source-Specific and State-Specific Impact Findings Required by the Clean Air Act.

EPA has not adequately demonstrated that the individual or category of sources it proposes to regulate under the proposed FIP cause or interfere with ozone attainment or maintenance in downwind states, but instead uses grossly inaccurate assumptions in its analysis and modeling rendering the entire FIP fatally flawed.

The 4-step framework as applied in the Proposed Rule identifies no sources or emissions activities in one state that significantly contribute to downwind air quality problems in another state (as the Good Neighbor provision of the CAA requires). Even for states that are contributing to nonattainment or interfering with maintenance, EPA has established no data to support which non-EGU emission sources within the state are "potentially controllable," would "have the greatest ppb impact on downwind air quality" or be "make meaningful air quality improvements at the downwind receptors at a marginal cost threshold" as EPA's own interpretation of the Clean Air Act dictates.[9] Without this information, EPA's FIP is arbitrary and capricious. *State Farm*, 463 U.S. at 43 (an agency rule is arbitrary and capricious if the agency has "entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise").

Clean Air Act § 110(a)(2)(D) requires SIPs to contain adequate provisions to prevent "any source or other type of emissions activity within the State" that contribute significantly to NAAQS

[9] Screening Assessment at 2.

nonattainment in another state or interference with maintenance. There has been no attempt to gather or model the source-specific data needed to determine what sources, if any, should be subject to regulation to address interstate transport of NOx. For the Proposed Rule, EPA has conducted a Non-EGU "Screening Assessment"[10] to identify costs and controls, but EPA itself acknowledges that this screening assessment "is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs."[11]

EPA has never used such modeling and estimation to impose unit-level emission limits. While EPA points to the screening assessment is used in CSAPR, and which was affirmed by the Supreme Court in *EPA v. EME Homer City Generation, LP*, 572 U.S. 489 (2014), there EPA was allocating state-level emission budgets and was based on "complex modeling to establish the combined effect the upwind reductions projected at each cost threshold would have on air quality in downwind States." *Id.* at 1596.

The record lacks the data needed to impose source-specific emission limits, and EPA has made no effort to develop similar source-specific modeling for non-EGUs. To the contrary, EPA's assessment, while starting with state-specific modeling to identify "linked" states, then proceeds to ignore any state-specific distinctions in evaluating the emission sources that should be subject to regulation. Specifically, after EPA identified "linkages" from a state to a downwind receptor based on as little as a 1% modeled impact on the design value, the Screening Assessment identifies industries that, without regard to those same state linkages, had over an arbitrarily set threshold of either 0.1 ppb impact on a single receptor or as low as a 0.01 ppb impact on at least 10 receptors.[12] The Proposed Rule then, without any technical or legal basis, assumes that, for those industries, every source within the same industry code has a significant contribution or interferes with maintenance and thus is subject to regulation.

Compounding this generalization, the Proposed Rule then assumes that the same controls and the same efficiency, can be achieved at all of these sources, using the same technology, and at the same cost, with no consideration of the size, age, past performance, or any other individual data from any single facility or emission unit.

While EPA could support industry-wide modeling of EGUs as a sufficient basis to impose state NOx budgets in *EME Homer*, the Proposed Rule's attempt to impose source- and emission unit-specific emission limits based on nothing more than generalized assumptions of what various industries that happen to be located in at least one "linked" state is untethered from any attempt to reduce significant contribution to nonattainment or interference with maintenance of the NAAQS and is patently insufficient. EPA cannot impose source and unit-specific emission requirements without first confirming that it screening assumption hold up when applied to the actual states, sources, and emission units that will be subject to regulation. Otherwise, EPA has "entirely failed

[10] Proposed Rule Non-EGU Screening Assessment.

[11] Non-EGU Screening Assessment at 7.

[12] *Id.*

to consider an important aspect of the problem" and "offered an explanation for its decision that runs counter to the evidence before the agency." *State Farm*, 463 U.S. at 43.

C. EPA's Sweeping Pollution Control Generalizations and Assumptions are Unproven and Inaccurate and Cannot Support the Proposed Rule' Emission Limits.

EPA cannot shift its burden to the states and affected sources to prove that its strategy is technologically and/or economically infeasible for each unique source that EPA proposes to regulate by the FIP. Rather, it is EPA's duty to provide "the factual data on which the proposed rule is based" and "the methodology used in obtaining the data and in analyzing the data." 42 U.S.C. § 7607(d)(3).

EPA's record for the Proposed Rule does not support the emissions controls or limits in the Proposed Rule, and in many cases, it contradicts the conclusions in the Proposed Rule. For example, while the Proposed Rule states that the "types of emissions control technologies on which the EPA proposes to base the emissions limitations that would take effect for the 2026 ozone season … generally are intended to be consistent with the scope and stringency of RACT requirements for existing major sources of NO_X" 87 Fed. Reg. at 20,101-102, the emission limits EPA proposes for the iron and steel industry assume, without support that emissions reductions of 25% to 50% can be achieved beyond recently-determined emission limits, including Ohio RACT limits for blast furnaces and reheat furnaces. *Id.* at 20,145, Table VII.C-3. Other limits are based on achieving similar reductions beyond recently established Best Available Control Technology ("BACT") determinations. *See id.*[13][14] The Proposed Rule not only leaves unanswered why emissions are capable of being reduced 40% from a BACT determination made last year, but also how such a limit can be imposed not only on new sources, but on existing sources as well. When the results of EPA's generalized assumptions are emissions limits that radically depart from EPA's own purported basis for establishing them, the adequacy of EPA's data and rationale for the Proposed Rule must be called into question.

EPA's proposed emission limits are also based on unsupported assumptions that pollution controls that have never been demonstrated in the iron and steel industry are feasible and effective—so effective that they will now result in substantial (40%-50%) reductions in emissions beyond current best-performing sources. As just one example, EPA has assumed that selective catalytic reduction ("SCR") is broadly available to reduce emissions from numerous sources,

[13] The Proposed Rule's emission limit for Ladle/tundish Preheaters is based on an assumed 40% reduction from Nucor Kankakee's BACT permit limit, which was issued in 2021. 87 Fed. Reg. 20,145, Table VII.C-3.

[14] Also, U.S. Steel's BRS facility underwent PSD review in 2013 and the new EV facility underwent PSD review in 2021. BACT analyses were submitted with both applications. EPA provided comments on the draft BRS permit in 2013 but did not comment on the 2021 application. In both instances, the application of SCR, NSCR, and other post-combustion controls for EAFs and other units at the facility was eliminated from consideration because the technology is not technically feasible. See e.g., BACT Analysis in support of the U.S. Steel's BRS facility Air Permit Application for Permit 2445-AOP-R0, dated Oct. 11, 2021. Other PSD permits issued to EAFs in recent years, all subject to review and comment by USEPA, reach similar conclusions.

including blast furnaces and basic oxygen furnaces, and coke ovens, to reduce emissions by as much as 50% from currently permitted limits, along or in combination with low-NOx burners. There is nothing in the record to show that SCR has been installed on any of these emission sources, let alone that doing so would result in the emission reductions EPA projects. The only reference appears to be a 2017 article from the Arid Zone Journal of Engineering, Technology and Environment stating that "[t]he combination of low NOX burner (LNB) and Selective catalytic reduction (SCR) is capable of reducing emission for up to 90% and above."[15] The paper does not indicate that this is based on any real-world application, however, and cites only studies of the use of SCR for other sources. EPA's own 2020 assessment for the 2008 Revised CSAPR rule did not consider SCR for the primary metals manufacturing industry.[16] As AISI has also already explained in comments on CSAPR, low-NOx burners were also recently eliminated as a control option for blast furnace stoves fueled primarily by blast furnace gas.[17] Yet EPA proposes to achieve 40-50% reductions at blast furnaces using "burner replacement" for these same stoves.[18]

Similarly, for Taconite Kilns, EPA proposes to assume that low-NOx burners will result in a reduction of 40% of NOx emissions.[19] There is nothing in the record to support this conclusion.

It is EPA's obligation to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *State Farm*, 463 U.S. at 43; *see also* 42 U.S.C. § 7607(d)(3) (the statement of basis and purpose must include "the factual data on which the proposed rule is based," "the methodology used in obtaining the data and in analyzing the data," and "the major legal interpretations and policy considerations underlying the proposed rule"). Nonetheless, U. S. Steel has, in the time allowed, identified several inaccuracies and improper assumptions in the feasibility and effectiveness of pollution control equipment for the iron and steel industries, and has documented those findings in the attached reports found in Exhibits A-D.

D. EPA Cannot Proceed to a Final Rule on this Record, Because the Proposed Rule Is Based Upon Many Data Errors, Data Gaps, and Incorrect Assumptions, Which Leave the Rule Insufficiently Supported.

The Proposed Rule is based on a set of vague, nation-wide assumptions about the NOx emissions generated by regulated industries, the relative contributions to downwind receptors, the emissions controls that are available to reduce NOx, the effectiveness of these controls, and cost of installation and operation, and the time required to install and operate them. These broad assumptions are generally not to be found in the record. Where U. S. Steel has painstakingly

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[15] EPA-HQ-OAR-2021-0668-0050.

[16] EPA-HQ-OAR-2020-0272.

[17] AISI Revised CSAPR Comments at 4.

[18] 87 Fed. Reg. 20,1045, Table VII.C-3.

[19] 87 Fed. Reg. 20,182.

sought to reconstruct EPA's analysis, the results indicate numerous errors and unwarranted assumptions.

U. S. Steel has endeavored to identify as many of these issues as it can in the limited time allowed and has documented these findings in the detailed reports prepared by Woodward and Curran, Black and Veatch, Trinity Consultants and Barr attached with these comments as Exhibits A - D. Prior comments have also identified numerous errors in EPA's emissions data. As U. S. Steel noted in its comments on the SIP denial rule, the emission estimates from other sources, including those in Arkansas, Illinois, Indiana, Ohio and Michigan – and in particular, emissions from the iron and steel sources in those states, are overstated and are inconsistent with prior state submittals. U. S. Steel SIP Comments are attached as Exhibits E & F. The Midwest Ozone Group has noted that numerous exceptional events have been improperly factored into the modeling used by EPA in the Proposed Rule.[20] Lake Michigan Air Directors Consortium (LADCO) has performed a detailed Source Classification Code ("SCC") based analysis of EPA's 2016v2 emissions modeling platform. In doing so, it found EPA's projected emission rates "are not consistent either with real-world emissions trends or regional emissions projection information."[21] The State of Minnesota similarly submitted a list of sources that it believes have incorrect future year projection rates.[22]

More fundamentally, however, EPA cannot proceed with a rule based upon many errors and incorrect assumptions. In order to avoid arbitrary and capricious rulemaking, "the agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) (*quoting Burlington Truck Lines, Inc. v. United States*, 371 U. S. 156, 168 (1962). An agency action is arbitrary and capricious "if the agency has relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise." *Id.* Here, the rationale provided by the agency is oftentimes completely unsupported by the record. At other times, it is implausible, if not contradicted by the record.

Even if EPA were to reject the state-specific evaluations contained in the numerous SIPs before the agency, a federal implementation plan must be based on an adequate understanding of the regulated emission sources, available controls, and their costs and effectiveness. The rulemaking procedures at section 307(d) of the CAA specifically require that a proposed rulemaking must "include a summary of—(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule" and "All data, information,

[20] Midwest Ozone Group SIP Denial Comments at 38-53.

[21] LADCO Minnesota SIP Denial Comments at 2.

[22] *Id* citing LADCO_EPA2016v2_Projections_Comments.xlsx.

and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule."[23] Furthermore, any final "promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation."[24] Relatedly, EPA has "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule."[25] The many errors and incorrect assumptions and the many ways explained throughout these comments that the Proposed Rule is not grounded in or adequately related to the modeling and data actually in the regulatory docket demonstrate that the record is simply insufficient to proceed with a final FIP.

II. EPA's Proposed Control Limits Go Beyond Any Level of Control Imposed by EPA, and Conflicts With Prior EPA Determinations.

EPA makes the assertion that the limits imposed by the Proposed Rule on non-EGUs "generally are intended to be consistent with the scope and stringency of RACT."[26] But this stated goal is inconsistent with the approach EPA actually took to setting the limits, and thus in violation of EPA's obligation to promulgate internally consistent rules.[27] In fact, for most (but not all)[28] units, EPA specifically considered RACT limits specified by states, then expressly rejected setting levels consistent with RACT, instead going on to propose limits up to a staggering 50% below the corresponding RACT limits considered.[29] These resulting proposed limits are also stricter than BACT, and inconsistent with recent BACT evaluations, which EPA had opportunity to comment on, which have ruled out SCR, NSCR, and other post-EAF NOx controls as not technically feasible for EAFs.[30] And the limits are even stricter than LAER, given that EPA can identify no new or existing facility nationwide in the industry that has demonstrated these limits in practice, and has identified no grounds for concluding that they may be feasible on an EAF.[31]

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[23] 42 U.S.C. § 6707

[24] Id.

[25] *National Lime Ass'n v. E. P. A.*, 627 F.2d 416, 433 (D.C. Cir. 1980)

[26] Proposed Rule at 20,101-02.

[27] *Hsiao v. Stewar*t, 527 F. Supp. 3d 1237, 1252 (D. Haw. 2021), quoting *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1141 (9th Cir. 2015) ("[A]n internally inconsistent analysis is arbitrary and capricious.").

[28] Non-EGU Sectors TSD at 42 (considering RACT for blast furnaces, reheat furnaces, ladle preheaters, annealing and galvanizing furnaces, but not for EAFs).

[29] See e.g. Proposed Rule at 20145 identifying Ohio RACT for blast furnaces at 0.06 lb, then setting a proposed limit at half that level.

[30] See e.g., BACT Analysis in support of the U.S. Steel's BRS facility Air Permit Application for Permit 2445-AOP-R0, dated Oct. 11, 2021.

[31] Notably, although EPA claims to identify an annealing furnace that successfully installed an SCR, EPA does not use that facility as a basis for the emission limits proposed for Annealing Furnaces, further calling into question whether the limits proposed by EPA are even possible in practice. And even if some type of annealing furnace ever installed an SCR, the concept of the application of an SCR on all annealing furnaces could not be justified, for instance some of the annealing furnaces at the U. S. Steel's BRS facility are small units that emit less than 6 tpy and run only intermittently such that they are not even stacked and thus neither CEMS not SCR would be possible to connect.

Furthermore, although EPA requests comment on the appropriateness of simply requiring RACT in states subject to the Proposed Rule,[32] EPA does not claim to have even attempted to model whether RACT might be sufficient to bring any given state's linked downwind receptors into attainment. Instead, EPA states that it "focuses on obtaining emissions reductions from non-EGU units that were quantitatively determined to have the most significant impacts on air quality improvements at the downwind nonattainment and maintenance receptors." [33]

But critically, as explained in more detail throughout these comments, EPA's modeling used to demonstrate statewide emission reductions necessary to reduce downwind emissions to acceptable levels was not based on the limits included in the Proposed Rule. [34] Instead, what EPA actually modeled was as follows: "We re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory. We specified CoST to allow replacing an existing control if a replacement control is estimated to be >10 percent more effective than the existing control. We did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control."[35] Notably, the output tables for this modeling show no reductions required at any EAF, and SCR only being added at certain BOF and Blast Furnaces and boilers.[36] Accordingly, to the extent that the modeling EPA actually performed shows that Good Neighbor provisions are satisfied with less stringent emission reductions, and without any reductions from a single U. S. Steel facility, EPA's choice to nevertheless go further than supported by its modeling and impose the draconian limits more stringent than RACT, BACT, or even LAER necessarily constitutes arbitrary and capricious overcontrol.

Finally, and independently, regardless of the rationality of requiring upwind states to meet RACT, it is certainly unreasonable, unlawful, and inconsistent with both EPA's past practice and court precedent interpreting the Good Neighbor provision to subject upwind states to emission limits that are stricter than the RACT limits imposed in the downwind states. After all, as EPA acknowledged when setting out the prior Good Neighbor framework upheld by the Supreme Court in *EPA v. EME Homer*, "Section 110(a)(2)(D)(i)(I) only requires the elimination of emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in other states; it does not shift to upwind states the responsibility for ensuring that all areas in other states attain the NAAQS."[37] Likewise, the D.C. Circuit's decision in *Wisconsin v. EPA* calls for aligning

[32] Proposed Rule at 20,097.

[33] Proposed Rule at 20,097.

[34] See Supra at section titled "EPA's Modeling Significantly Underestimates Reductions Associated with the Proposed Rule".

[35] Non-EGU Screening Assessment at 8.

[36] Non-EGU Screening Assessment at Table 6; see also excel file in regulatory docket titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List".

[37] "Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals" 76 Fed. Reg. 48,208, 48,210 (August 8, 2011).

upwind and downwind requirements to treat them consistently to the degree possible. Accordingly, whatever requirements are placed on upwind industry should not be more stringent than those applicable to industries subject to RACT due to actually being in a nonattainment area; it would be irrational, arbitrary, and capricious, when considering impacts to the same nonattainment or maintenance receptor, to force a source far away to enact stricter limits than a source actually in or next door to the nonattainment area.[38]

III. EPA Fails to Demonstrate that the Proposed Rule Avoids Overcontrol Because The Proposed Rule Fails to Evaluate Alternative Cost Thresholds for Non-EGUs.

EPA claims that the Proposed Rule continues to "apply the same approach as the prior three CSAPR rulemakings for evaluating 'significant contribution' at Step 3" including "evaluat[ing] NOX reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds)" and states that this approach "was upheld by the U.S. Supreme Court in *EPA v. EME Homer City*."[39] EPA is partially correct. The approach used by EPA in its prior three CSAPR rulemakings was upheld in *EPA v. EME Homer City* (subject to the ability of petitioners to pursue any as-applied challenges based on allegations of overcontrol). But that is not what EPA did in this Proposed Rule.

EPA's approach in the Proposed Rule is crucially different from that upheld by the courts in the past, because here EPA did ***not*** evaluate "NOx reduction potential, cost, and downwind air quality improvements available at various mitigation technology breakpoints (represented by cost thresholds)" with respect to non-EGUs. Instead, as explained below, EPA selected a cost-efficiency threshold for non-EGU controls based solely on total reductions available, instead of setting a cost threshold based on the controls strictly necessary to achieve attainment at downwind linked receptors. Accordingly, the control level selected for non-EGUs is wholly inconsistent with EPA's prior approach, has no basis in prior precedent, and fails to demonstrate that EPA is avoiding overcontrol, particularly since EPA failed to model whether a lower cost threshold for non-EGUs sources may also have achieved attainment at downwind receptors.

In the *EME Homer* CSAPR litigation, the Supreme Court approved an approach of modeling the reductions associated with several different cost thresholds of potential controls, and setting the cost threshold (and thus controls) at the lowest level needed to achieve attainment in downwind receptors.[40] But here, EPA set a cost threshold for non-EGUs based on the maximum

[38] Note that the stringency of controls is conceptually distinct from the amount of emissions reductions. If a given level of control on whatever industry most contributes to a downwind linked nonattainment or maintenance receptor is insufficient to fulfil a state's Good Neighbor obligation (something EPA has not demonstrated since EPA has not yet either modeled the highest industry contributors on a state by state basis, or accurately modeled the level of controls proposed in the rule), then the applicability of the controls can be extended to additional sources or industries, rather than requiring a specific industry to be more tightly controlled in an upwind state than RACT would require in the downwind state.

[39] Proposed Rule at 20,055.

[40] *EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 500 (2014) ("Under the Transport Rule, EPA employed a 'two-step approach' to determine when upwind States 'contribute[d] significantly to nonattainment,' and therefore in 'amounts' that had to be eliminated. At step one, called the 'screening' analysis, the Agency excluded as de minimis

amount of emission reductions potentially achievable (rather than based on the amount needed to resolve downwind receptors), and only modeled controls at that cost threshold ($7,500) without ANY modeling to see if incrementally lower cost thresholds could also achieve attainment at downwind receptors.[41]

Notably, EPA's use of cost thresholds in the Proposed Rule was radically different for EGUs and non-EGUs. The Proposed Rule's support documents do consider several incremental cost thresholds for EGUs in creating modeling scenarios, ranging from $1,600 to $11, 000. But for non-EGU's, EPA instead:

1. aggregated all proposed industries together, instead of setting industry specific cost thresholds like EPA did for EGUs;
2. selected only a single control scenario for consideration (i.e. all controls up to $7,500/ton) rather than the many control levels modeled for EGUs; and
3. rather than varying the level of controls required to reduce emissions from a set list of significant facilities (like the rule does for EGUs), for non-EGUs, the only modeling variations run by EPA were changing which units a preordained level of controls would be applied to.

As explained in the Policy Analysis TSD, only the following scenarios were modeled for their effect on ppb ozone concentrations at downwind receptors:[42]

- Engineering Analysis Base
- EGU only $1,600 cost threshold (SCR Optimize + Generation Shifting)
- EGU only $1,600 cost threshold (SCR Optimize + SOA CC + Generation Shifting)
- EGU only $1,800 cost threshold (SCR Optimize + SNCR Optimize + Generation Shifting)

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any upwind State that contributed less than one percent of the three NAAQS to any downwind State 'receptor,' a location at which EPA measures air quality. . . The remaining States were subjected to a second inquiry, which EPA called the 'control' analysis. At this stage, the Agency sought to generate a cost-effective allocation of emission reductions among those upwind States 'screened in' at step one. The control analysis proceeded this way. EPA first calculated, for each upwind State, the quantity of emissions the State could eliminate at each of several cost thresholds. . . . The Agency then repeated that analysis at ascending cost thresholds. Armed with this information, EPA conducted complex modeling to establish the combined effect the upwind reductions projected at each cost threshold would have on air quality in downwind States. The Agency then identified 'significant cost threshold[s],' points in its model where a 'noticeable change occurred in downwind air quality, such as . . . where large upwind emission reductions become available because a certain type of emissions control strategy becomes cost-effective.' For example, reductions of NOX sufficient to resolve or significantly curb downwind air quality problems could be achieved, EPA determined, at a cost threshold of $500 per ton (applied uniformly to all regulated upwind States).") (internal citations omitted).

[41] Proposed Rule at 20083; see also Non-EGU Screening Assessment at 4.

[42] See Policy Analysis TSD at 55-57, Tables C-12, C-13, and C-14.

- EGU only $1,800 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + Generation Shifting)
- EGU only $11,000 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting)
- EGU $11,000 cost threshold plus non-EGU Tier 1 at $7,500 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1)
- EGU $11,000 cost threshold plus non-EGU Tiers 1&2 at $7,500 cost threshold (SCR Optimize + SOA CC + SNCR Optimize + SCR/SNCR Retrofit + Generation Shifting + non-EGU Tier 1 + Tier 2)

Accordingly, as noted above, although different cost thresholds were evaluated for EGUs, *EPA never modeled the effect of different cost thresholds for non-EGUs*. Likewise, the "less stringent" and "more stringent" scenarios evaluated in the Regulatory Impact Analysis for non-EGUs only vary the scope of units evaluated, with the less stringent scenario subjecting fewer units to the Proposed Rule, and the more stringent scenario subjecting all Tier 1 and 2 units to the Proposed Rule regardless of their size, but all such scenarios assumed the same cost threshold for level of controls for all non-EGU regulatory scenarios.[43] Thus EPA has not demonstrated that the selected control efficiency of $7,500 per ton for non-EGUs avoids overcontrol, as compared to some lesser cost threshold (e.g. reflecting solely combustion controls like low-NOx burners and optimizations, without post combustion SCR retrofits), since EPA failed to model the effect of any lesser cost thresholds for non-EGUs.

This failure to model alternate cost scenarios is particularly untenable given that EPA's own cost modeling clearly showed that Tier 1 industries like Iron and Steel manufacturing had a "knee in the curve" at $1,000, and not the $7,500 threshold selected by EPA, as discussed below in the section regarding cost of controls.[44]

Because EPA failed to model the impact of control scenarios for non-EGUs associated with any lower cost threshold, the EPA has failed to demonstrate that the cost threshold chosen represents the lowest level of necessary controls that will "only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.'"[45]

[43] See Regulatory Impact Analysis at ES-7.

[44] See non-EGU Screening Analysis at 4, showing different cost-effective thresholds for Tier 1 and Tier 2 industries, but then ignoring this clear data and only evaluating the aggregate $7,500 cost threshold.

[45] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 137 (D.C. Cir. 2015) (quoting *EPA v. EME Homer City Generation, L.P.*, 572 U.S. at 515 n.18).

IV. EPA Fails to Demonstrate that the Proposed Limits and the Theoretical Controls They are Based on Are Technically Feasible at the Facility and Unit Specific Level.

It would be arbitrary and capricious to require something that is not possible.[46] Yet, as explained in more detail below, the Proposed Rule would impose limits on iron and steel emission units below what have ever been achieved in the industry, based on little more than speculation about feasibility of controls that have never been demonstrated in practice in the industry. And in any case, EPA must show more than bare possibility to justify the emission limits in the Proposed Rule. Congress has made the express determination that "reasonably available control technology" (RACT) is the appropriate level of control when addressing even nonattainment areas themselves.[47] And it would be arbitrary and inconsistent with the scheme of Title I and intent of Congress for sources in upwind states to be subject to limits stricter than the RACT limits applicable within nonattainment areas. In interpreting this standard, EPA has consistently found that "RACT for a particular source continues to be determined on a case-by-case basis considering the technological and economic feasibility of reducing emissions from that source."[48] In evaluating technical feasibility EPA must evaluate, on a facility and emission unit specific basis, "the source's process and operating procedures, raw materials, physical plant layout, and any other environmental impacts such as water pollution, waste disposal, and energy requirements" "the operation of and longevity of control equipment" "the space available in which to implement such changes" and "Reducing air emissions may not justify adversely affecting other resources by increasing [other types of] pollution" or "creating excessive energy demands."[49] Accordingly, EPA is correct to speak throughout the Proposed Rule about whether the controls proposed are "feasible" and "appropriate,"[50] but EPA must do more than talk about appropriateness, EPA must demonstrate that the proposed limits are both technically and economically feasible on a facility specific basis. This EPA has not done, and the Proposed Rule is unlawful without doing such analysis. And in any case, EPA has an independent "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[51] and EPA may not "promulgate rules on the basis of inadequate data, or on data that,

[46] Notably even EPA relies on not being required to achieve the impossible. See Proposed Rule at 20062 ("implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity.").

[47] 42 U.S. Code § 7502; see also State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,073 (April 28, 1992).

[48] State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,073 (April 28, 1992).

[49] Id. at 18,073-74.

[50] E.g., Proposed Rule at 20,043, 20,056, 20,076, 20,080, 20,090 (discussing whether control technologies, measures and strategies, compliance flexibility, timing, and cost are "appropriate"); see also id. at 20144, 20147 (discussing whether certain limits are "feasible or appropriate").

[51] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

to a critical degree, is known only to the agency."[52] And thus EPA's assumptions regarding feasibility in the Proposed Rule must be adequately justified, yet, as explained in more detail in later sections herein specific to different types of U.S. Steel's operations, EPA has not done so.

V. EPA's Cost Analysis is Not Reasonable

As noted elsewhere in these comments, EPA must consider economic feasibility in setting control measures under RACT, the standard Congress has specified as applicable to NAAQS nonattainment areas.**53** EPA does have some discretion when setting cost effectiveness thresholds in rulemaking proceedings. But, "the law does require EPA to 'cogently explain why it has exercised its discretion in a given manner.'"[54] Furthermore, although EPA is entitled to make assumptions in its cost analyses, it has a "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[55] EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[56] EPA's approach to cost estimates and cost thresholds in the rule violate these principles and/or makes unreasonable assumptions and conclusions in a variety of ways as explained below.

A. EPA's Ignores High Variability of SCR Retrofit Costs

EPA acknowledges that its cost estimates are averages, and not reflective of individual facility retrofit costs. [57] But EPA does not address its historic acknowledgment that SCR retrofit costs are highly variable on a facility-by-facility basis making it inappropriate to apply an industry average cost threshold to all facilities in an industry outside of an emission trading program.

In prior Good Neighbor rulemakings, when commenters pointed to the high variability in cost as a critique of EPA's consideration of SCR as an available retrofit technology, EPA acknowledged high variability of SCR retrofit costs, but replied that such variability was not an issue because the emission trading scheme imposed in such prior regulatory regimes "incentivizes emission reductions at units where they are cheapest" and allowed for a choice between installing the controls, or purchasing emission credits such that reductions need not be done at facilities with high retrofit costs.[58] That rationale does not apply here. EPA expressly rejects an emission trading

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[52] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[53] See State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental, 57 Fed. Reg. 18,070, 18,073 (April 28, 1992).

[54] *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1142-43 (9th Cir. 2015) (internal citations omitted) (in regional haze context, striking down a BART determination where EPA provided no supporting rationale for why one cost level was acceptable, but another was not).

[55] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

[56] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[57] Proposed Rule at 20,090.

[58] EPA Response to Comments to the Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, pg. 98.

scheme for non-EGUs. Instead, under the command-and-control scheme adopted by EPA in the Proposed Rule, all impacted non-EGU emission units, particularly in the iron and steel industry subcategory, are essentially required to install SCRs regardless of the site-specific costs. EPA cannot continue to rely on an industry average cost to find SCR as categorically cost effective as EPA attempts to do in the Proposed Rule.

B. Cost Estimates Inaccurately Assume Year-Round NOx Reductions.

EPA's cost-per-ton reduction calculations are unreasonably skewed because they assume that SCR will be run all year at facilities that install it and calculates expected cost per ton on the basis of annual tons of NOx reduced, despite the fact that the NOx emission reductions being sought by EPA in the Proposed Rule are only to address ozone season emissions. For instance, EPA estimates that selection of SCR in the iron and steel industry may be associated with 948 ozone season NOx reductions, at an annual cost of $9,886,092. [59] If EPA had calculated the cost per ozone season ton of NOx reduced, this would result in an estimate of $10,428 per ton of NOx reduced[60] (notably above the cost threshold of $7,500 set by EPA). But EPA instead, without justification, lists the average cost per ton as $4,345[61], which would only be the case if the ozone season tons were extrapolated to assume continuous annual reductions.[62]

This is erroneous both legally and factually. As a legal matter, EPA only has authority to reduce ozone season emissions under the Proposed Rule and thus should limit itself to assessing the cost of ozone season reductions. Furthermore, as a factual matter, facilities will not operate SCR during the non-ozone season as EPA has acknowledged in the Proposed Rule in "quite typical" in the context of EGUs.[63] There are sound technical, economic, and environmental reasons for not operating SCR outside the ozone season, particularly due to the O&M cost associated with operation of the SCR, and in order to attempt to extend the life of the catalyst given the high cost of replacing the catalyst and how quickly the catalyst can be deactivated under the process characteristics of iron and steel furnaces such as BOFs and EAFs, as discussed above, if it were run continuously. For both independent reasons, costs estimates should instead account for the cost per ozone season ton reduced. (which is in many cases higher than the $7,500/ton screening threshold set by EPA even using EPA's own cost estimates).

C. Improper Aggregation of Industries in Setting Effective Control Cost Threshold

EPA's selection of a $7,500 cost threshold for selecting applicable controls was skewed high by grouping all Tier 1 and 2 industries together without justification. As shown in the below

[59] See Non-EGU Screening Assessment at Table 9.

[60] $9,886,092 / 948 = $10,428.

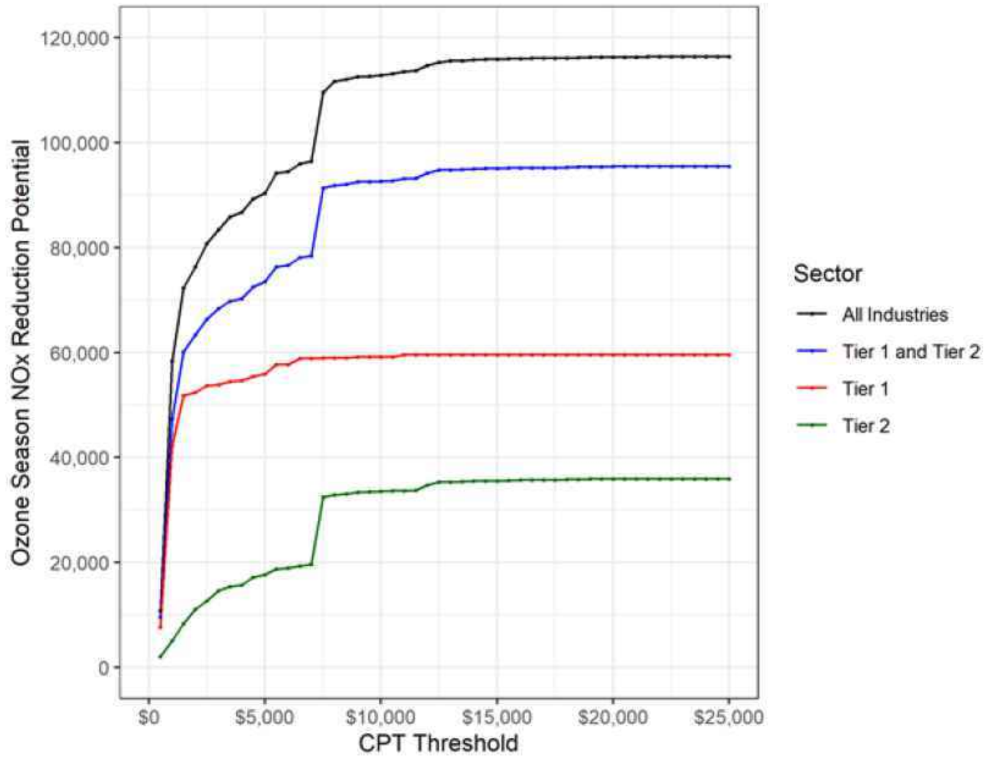
[61] See Non-EGU Screening Assessment at Table 9.

[62] $9,886,092 / (948 X (12 / 5)) = $4,345.

[63] Proposed Rule at 20,078 & n.146.

figure, EPA's cost modeling clearly showed that Tier 1 and 2 industries each had a significantly different "knee in the curve" (i.e. a significantly different cost effectiveness threshold).[64]

Figure 1. Ozone Season NOx Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and Other Industries



Based on the above chart, Tier 1 industries had a "knee in the curve" at $1,000 per ton, far lower than the cost effectiveness threshold of approximately $7,500 for Tier 2 industries. Accordingly, because this model showed that cost effectiveness could differ by industry, and because EPA conducted industry specific cost modeling for the EGU industry, EPA should have estimated industry specific cost effectiveness thresholds. But in any case, it was arbitrary for EPA to aggregate these cost curves without any explanation and thus subject all non-EGU industries to the $7,500 cost effectiveness threshold despite EPA modeling affirmatively showing that threshold was not even remotely accurate for Tier 1 industries.

VI. Modeling Problems

The modeling used in support of the Proposed Rule included many questionable and unreasonable assumptions and processes. The sections below summarize many such issues, but the attached report from Woodard and Curran includes more detailed and technical critiques of the modeling underlying the rule which EPA must consider, and which is hereby incorporated by reference.

[64] Non-EGU Screening Assessment at Figure 1.

A. Low Precision/Accuracy:

As discussed in more detail in the attached Woodard report, EPA compared the CAMx model used by EPA to evaluate state contributions to linked receptors with actual monitoring data for each such receptor to evaluate the accuracy and precision of the CAMx model. For example, the result showed a standard deviation of 8ppb for modeling at the relevant Brazoria County, Texas receptor, [65] and only accounted for 37% of observed variation at the receptor. Although EPA claims this is on par with other CAMx models so as to not invalidate use of CAMx for the Proposed Rule, the imprecision of the CAMx modeling should be taken into account when EPA sets its levels of what contribution amount to consider to be "significant" for purposes of determining the applicability of the Proposed Rule. Given that the standard deviation for any CAMx prediction at the Brazoria receptor was up to 8pbb, it is not reasonable or rational for EPA to rely on CAMx to make finetuned distinctions between industries modeled to have impacts at 0.01ppb (the screening level selected by EPA for industry significance), since EPA's own analysis shows that the model is simply not precise enough to statistically differentiate between 0.01ppb, 0.1ppb, and 1ppb. Furthermore, EPA's communications discussed in the attached Woodard report demonstrate that EPA was aware of model "noise" due to model outputs being copied and handled over multiple operating systems and that numerical noise in model outputs could be present and could contribute to variations in modeled concentrations. If that noise was on the order of 0.01 ppb, that would be yet another reason that the modeling could not be relied on to differentiate between impacts at that level of granularity, and thus that such a level below background "noise" cannot be considered significant. Accordingly, EPA should base any determinations of modeled significance at a precision no smaller than 1pbb, so as to at least be within the same order of magnitude as the model's standard deviation.

B. False Geographic Equivalence:

EPA modeled percent reductions needed across each state as if reductions in one part of the state had the same effect as another, rather than modeling how reductions at particular sources affect the NAAQS compliance in downwind states.[66] EPA may have been able to do this under past rules which merely set statewide budgets and did not impose emission unit specific emission limits applicable on a facility level. But if EPA continues to propose facility and unit specific limits, then (as explained in Sections I, IV and XIV regarding EPA authority to issue emission unit limits applicable at a facility level) EPA must model whether such facility has an impact sufficient to justify regulating them under the Good Neighbor clause, rather than the individual limits applicable here. This is particularly true given the fact that CAMx can be used to predict facility level impacts, and EPA simply chose to run the model without that available parameter.

[65] See excel chart labeled "CAMx 2016v2 MDA8 O3 Model Performance Stats by Site".

[66] Policy Analysis at 33 n. 41.

C. Disregard of Emission Increases:

As described in the section herein concerning feasibility of SCR installation, the temperature operating range of an SCR does not match the temperature range needed for the safe and effective operation of a baghouse, such that even if it were technically feasible to install, it would likely require increasing the source's NOx, VOC, PM, SO2, CO, ammonia and greenhouse gases and other pollutants due to the need for additional natural gas and electricity needed to heat, cool, or clean up the flue gas to make it amenable to operable SCR temperature ranges and tolerances. EPA appears not to have accounted for this emission increase (or at least offset against any expected reductions). This in turn will also require analysis of whether increased VOC, PM, NOx, CO, ammonia, etc. emissions as a result of installing SCR would have an adverse effect on compliance with other NAAQS.

D. Ignoring Emission Reductions in Favor of Overcontrol:

As noted above, the model appears to significantly underpredict emission reductions associated with the Proposed Rule, by not even attempting to include all facilities subject to the Proposed Rule or attempting to quantify the actual reductions resulting from the emission limits in the Proposed Rule. This is important to correct before issuing a final rule because ignoring emission reductions resulting from the Proposed Rule would lead to impermissible overcontrol by setting limits that reduce emissions by far more than EPA has modeled are necessary to result in attainment (especially with respect to the Brazoria County, Texas receptor). Accordingly, if EPA intends to proceed with implementing unit specific control emission limitations, EPA must either redo the overcontrol analysis using estimated reduction estimates based on the emission limits proposed in the Proposed Rule, and/or EPA must make the limits less stringent so as to match the statewide emission reductions modeled to not result in downwind attainment without overcontrol.

E. Erroneously Assuming Linear Impacts:

EPA assumed impacts were linear between emission reductions and ppb reductions at receptors, even though EPA acknowledged they are not in fact linear.[67] Although EPA attempted to account for the nonlinear relationship by applying an adjustment factor that is specific to the state and receptor, such adjustment factors do not account for different locations of emission sources within a given state and thus do not adequately correct the erroneous assumption of linear reductions. This is particularly problematic with respect to the U. S. Steel's Arkansas facility, since it is on the far opposite side of the state from the Brazoria County, Texas receptor, yet EPA's adjustment factors treat any reduction at U. S. Steel's Arkansas facility the same as NOx sources in places like Texarkana and El Dorado which are hundreds of miles closer to the Brazoria receptor. Moreover, EPA fails to provide any rationale for why it is accurate or reasonable to apply the same adjustment factor for these geographically remote locations to correct EPA's admittedly erroneous assumption regarding linearity of impacts in relation to emission reductions. Finally, the HYSPLIT modeling conducted by Woodard & Curran and discussed below in Section

[67] Policy Analysis at 33 n. 42.

XIV. of these comments shows that it is important to differentiate between effect of impacts in different portions of the state, because EPA's assumptions of linearity regardless of location in the state is contradicted by the back-trajectories modeled by HYSPLIT, demonstrating that the U. S. Steel's Arkansas facility is not linked to ozone high days at the Brazoria receptor.

F. Mismatch Between Modeled Reduction and Proposed Controls:

EPA's modeling does not accurately reflect the control efficiencies EPA assumes (and requires) in the Proposed Rule. For instance, it appears that EPA performed a modeling run where EPA assumed emission reduction of 30% across all covered sources to demonstrate attainment status at nonattainment and maintenance receptors, and a model run based on the statewide emission reductions EPA expected based on the non-EGU screening assessment. But neither of these modeling runs reflect the emission standards that EPA actually proposes. As previously noted, the modeling run based on the non-EGU screening assessment significantly undercounted emission reductions associated with the Proposed Rule limits. And the modeling run assuming across the board reductions of 30% likewise does not match the limits in the Proposed Rule, which assume unit specific limits far more stringent than 30% in many cases. For EAFs, for instance, "EPA based the emission limit of 0.15 lb/ton of steel on projected reduction efficiency of 40-50% as compared to existing permit limits for EAFs".[68] EPA cannot haphazardly model one set of assumptions and then propose something totally different. EPA should conduct modeling that actually reflects the rule being proposed.

G. Improper Significance Screening Threshold

It is unreasonable for EPA to depart from its August 2018 memorandum regarding determinations of state significant contribution thresholds by now requiring evaluation in light of a 0.7 ppb significance threshold rather than the 1 ppb significance threshold approved in the August 2018 memo.

In the first place, EPA's August 2018 memo provided modeling to support the conclusion that a 1 ppb threshold is generally comparable to a 1% threshold for the 2015 ozone NAAQS in terms of the contributions it would cover, and it is arbitrary for EPA to abandon that conclusion without performing any technical analysis to suggest that EPA's prior conclusion is flawed, or even retracting the August 2018 memo.

Second, 1 ppb is the significant digit for reporting ozone monitoring data under the NAAQS.

Third, the imprecision of EPA's modeling (as discussed above) demonstrates that a significance threshold below 1 ppb simply cannot be justified since the model lacks the capability to distinguish impacts below that level.

[68] Non-EGU Sectors TSD at 43.

Finally, EPA has already determined that 1ppb represents the level at which a single facility presents a significant impact under the 8 hr Ozone NAAQS in the context of PSD permitting.[69] In making the determination that 1ppb represents the significant impact level (SIL) for evaluating whether a given source may contribute significantly to any attainment issues with the 8 hr Ozone NAAQS, EPA engaged in actual statistical analysis to find what "degree of change in concentration is, thus, indistinguishable from the inherent variability in the measured atmosphere and may be observed even in the absence of the increased emissions from a new or modified source" and determined that "changes in air quality within this range [i.e., the relevant SIL] are not meaningful, and, thus, do not contribute to a violation of the NAAQS."[70] By contrast, EPA provides no analysis for why the various proposed significance screening levels in the Proposed Rule (0.7ppb for an entire state, and 0.01 for an entire industrial sector) represent a significant contribution with respect to air quality at downwind receptors.[71]

EPA bases its significance level for statewide emissions on consistency with past CSAPR rulemakings.[72] To be sure, such prior rulemakings also used 1% of the relevant NAAQS as a screening threshold for screening out states without any significant contribution, and that threshold was upheld in 2014 by the Supreme Court in *EME Homer*. But crucially, the past rulemakings EPA points to and the Supreme Court's decision in *EME Homer* all pre-date EPA's 2018 publication of the Ozone SIL and associated modeling and express finding that any contribution under 1ppb is indistinguishable from background variability and thus cannot be characterized as a significant contribution. EPA cannot simply ignore its own more recent modeling and determinations with respect to the 8hr Ozone NAAQS simply by saying it wishes to be consistent with assumptions made before the SIL analysis and determinations were made by EPA. EPA must at minimum explain why it is concluding that a level may constitute a significant contribution that EPA has previously determined by statistical analysis to *not* be significant.

EPA bases its significant contribution threshold for all non-EGU industries on an eyeballed review of a figure comparing relative impacts of different industries, and EPA concludes based on subjective review that "perhaps 0.05 ppb or 0.01 ppb could serve as breakpoints in the data" but ultimately selects 0.01 ppb as "a meaningful conservative breakpoint for screening out non-impactful industries."[73] This analysis is flawed for multiple reasons. First, in selecting 0.01 pbb, EPA asked the wrong question, namely, "what are we confident is so de-minimis as to be

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[69] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (April 17, 2018). https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf.

[70] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (April 17, 2018). https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf.

[71] Compare, 42 U.S. Code § 7410(a)(2)(D)(i)(I), limiting application of the Good Neighbor provision to "amounts which will . . . contribute significantly to nonattainment".

[72] Proposed Rule at 20,074.

[73] Non-EGU Screening Assessment at 22-23.

justifiably screened out" rather than the question posed by the statute, i.e., "what is significant enough to constitute a significant contribution." Although it is justifiable to screen out any industry with impacts below 0.05 or 0.01 pbb impacts to downwind nonattainment and maintenance receptors, that does not mean that it is reasonable to automatically assume that anything above that level is a significant impact. Even more importantly, EPA's subjective comparison of industries to each other can at most only answer the question "what industries are more significant than other industries" and not the statutory question of what "amount" of emissions constitutes a "significant contribution" to downwind receptors. Actually, demonstrating what impact constitutes a significant contribution instead requires statistical analysis evaluating the variation in the Ozone 8-hour design value at each monitoring site, to prove that 0.01 ppb is indeed a threshold above which out of state NOx emissions could significantly impact Ozone attainment, something EPA has not attempted here. In any case, it is arbitrary for EPA to conclude 0.01 ppb from an entire industry can constitute a significant contribution to downwind receptors without even addressing EPA's prior statistical analysis concluding that any amount below 1ppb from even an individual facility is "not meaningful" and so insignificant as to be "indistinguishable from the inherent variability" at downwind receptors and "not contribute to a violation of the NAAQS."

H. Failure to do Any Backtrajectory Modeling or Otherwise Evaluate Consistency and Persistence of Impacts Predicted in CAMx

The model used by EPA (CAMx) only looks at five to ten elevated ozone days in forming its conclusions regarding state contributions to linked predicted nonattainment and maintenance receptors. Due to the complexity of the subject matter, it is questionable whether this small sample size reasonably reflects consistency of predicted contributions. In any case, because EPA does not evaluate consistency and persistence of the impacts found, EPA should have performed some other backtrajectory modeling, such as HYSPLIT, to confirm what geographic regions were contributing to days predicted to be over the NAAQS. At a minimum this should have been performed for Arkansas and Mississippi which were linked to only a single downwind maintenance receptor, to evaluate what sources and geographic areas could be contributing to these predicted high-ozone days, and whether any impact on the maintenance receptor is truly consistent and persistent enough to be classified as a significant contribution. After all, it would not be reasonable to consider an inconsistent or transient effect a "significant contribution." Notably, EPA itself used HYSPLIT in this rulemaking to evaluate environmental justice impacts on a facility specific level for EGUs[74] (though EPA did not use it to evaluate EPA's authority to regulate individual facilities under the Proposed Rule in the first place). EPA has also previously approved the use of HYSPLIT to screen out areas in the similar context of regional haze.[75]

Because EPA failed to perform the modeling needed to assess the significance of state and facility contributions to downwind receptors in the first instance, and because it bears directly on EPA's authority to regulate facilities and states at all under the Good Neighbor provision, EPA

[74] Policy Analysis TSD at 67.

[75] 87 Fed. Reg 7734 (Feb 10, 2022).

must consider any such CAMx or HYSPLIT modeling whenever it is completed in determining applicability of any final rule.

I. Elimination of "Well Controlled Sources"

EPA makes the cryptic observation that it "well-controlled sources that still emit > 100 tpy are excluded from consideration" as part of the modeling related to the non-EGU Screening Assessment, including compliance costs and the emission reductions required in order to meet Good Neighbor obligations.[76] EPA does not explain how a source was determined to be "well controlled" enough to be excluded, and in any case, because EPA expressly set the emission limits in the Proposed Rule below anything EPA found that any emission unit in the iron and steel industry currently achieved. Notwithstanding, any so-called "well controlled" source EPA eliminated from analysis must still have been above the Proposed Rule limits. Accordingly, EPA must explain why sources were excluded from analysis as "well controlled" despite presumably not being well controlled enough to meet the limits EPA now proposes. Although EPA enjoys flexibility in how to perform modeling, it has a "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[77] and EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[78]

J. Internal Inconsistency Regarding Anticipated Reductions

The Proposed Rule contains many internal inconsistencies regarding the extent of reductions assumed by EPA in performing modeling and setting proposed emission limits. For example, just with respect to EAFs, the rule Proposed Rule states that it "[a]ssumes 25% reduction by SCR," whereas the Non-EGU Sectors TSD states that it projects "efficiency of 40-50% as compared to existing permit limits for EAFs" and "minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of low-NOx burners and selective catalytic reduction."[79] And the Non-EGU Screening Assessment estimated no reductions from EAFs.[80] In order to draft a non-arbitrary rule, EPA must make a consistent assumption about the emission reductions associated with the Proposed Rule, and actually use that same assumption when modeling costs, feasibility, and air quality impacts at downwind receptors.

K. Use of AEO Rather Than Current Emission Inventories

When describing the non-EGU emission inventory development used in the air quality modeling to identify nonattainment and maintenance areas and the significance of state contributions thereto, the Proposed Rule states that EPA started from the 2016v2 platform, then

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[76] Proposed Rule at 20,083.

[77] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

[78] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[79] Non-EGU Sectors TSD at 43.

[80] Non-EGU Screening Assessment at Table 6.

"The future year non-EGU point inventories were grown from 2016 to the future years using factors based on the AEO 2021 . . ." [81] But AEO 2021 does not appear to be an industry emissions inventory, but instead only appears to track energy consumption in various industries.[82] It is not reasonable to use this approach when EPA had actual emission inventories (such as the 2019 NEI) available, particularly for EAFs. Unlike EGUs, whose emissions might be expected to strongly correlate to energy consumption at the plant, EAFs NOx emissions are not primarily driven by by the combustion of fossil fuels. Thus, EPA should compare actual updated emission inventories with the AEO to demonstrate its accuracy and appropriateness as a basis for developing emission inventories.

VII. The Proposed Rule Runs Afoul of Many Legal Doctrines:

A. Major Questions Doctrine:

Multiple aspects of the Proposed Rule implicate the major questions doctrine which provides that agencies cannot unilaterally resolve questions of "vast economic or political significance" unless Congress has unambiguously authorized it to do so.[83]

1. The Proposed Rule would mandate generation shifting in the EGU sector in many ways, first, EPA sets emission budgets for EGUs based on assuming that generation shifting will occur, [84] which is a form of expressly requiring generation shifting, by setting limits too low to achieve in the absence of generation shifting. Second, EPA further forces generation shifting through the creation of the "backstop daily rate for large coal EGUs"; which would only apply to coal fired plants, and not natural gas plants,[85] and are expressly designed to make coal fired EGUs, but not natural gas fired EGUs, either "retrofit [with SCR] or retire."[86] This solely targets coal in order to reshape the energy sector to EPA's preferences, in a similar manner to that at issue in the challenges to the Affordable Clean Energy and Clean Power Plan rules. The Supreme Court has accepted review of a set of cases challenging those rules, arguing that the major questions doctrine prohibits EPA from forcing generation shifting or otherwise restructuring the nation's energy system.[87] A decision is expected by June 2022, and any final rule must account for and comply with any interpretation of the major questions doctrine in that case.
2. The Proposed Rule's historically unprecedented use of the Good Neighbor provision to impose emissions limits on a unit specific basis for entire industries, without any

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[81] Proposed Rule at 20,064.

[82] See AEO 2021, narrative available at https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

[83] Util. Air Regul. Grp. v. EPA, 573 U.S. 302, 324 (2014).

[84] Proposed Rule at 20,081.

[85] Proposed Rule at 20,110-11.

[86] Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard, at ES-7.

[87] See West Virginia v. Environmental Protection Agency, No. 20-1530, and linked cases.

consideration of unit specific feasibility or demonstration that the source itself is contributing to any nonattainment or maintenance site also runs afoul of the major questions doctrine. The text of the Good Neighbor provision, which focuses only on limiting amounts of emissions significantly contributing to actual nonattainment of maintenance issues in downwind states does not clearly authorize the vast industry shaping and reorganizing that EPA attempts to issue in the Proposed Rule.

B. Chevron Doctrine

Multiple aspects of the Proposed Rule exceed the discretion granted to EPA under the statutory text, and thus will not be protected by *Chevron* deference,[88] and may serve as a basis for challenges to *Chevron* itself, or at least to further limits on EPA's deference under *Chevron*.

1. The Proposed Rule only applies by virtue of EPA's disapproval of various SIP plans. In disapproving those state plans (which is a statutory prerequisite for EPA authority to issue the Proposed Rule) EPA effectively asserted that it would prefer to institute a FIP as opposed to individual SIP demonstrations due to a wish to address ozone transport in a "nationally uniform approach" with "nationwide scope and effect" based on a "common core of nationwide policy judgements."[89] But EPA lacks discretion to decide that regional ozone transport is a national problem that requires national uniformity (e.g. by setting industry wide emission limits based on a "common core of nationwide policy judgements" without regard to state specific contribution considerations). Congress already unambiguously made a contrary decision by making EPA's discretion to implement a FIP subject to SIP submissions that EPA "shall" approve if the statutory elements are met. *See* 42 U.S.C. § 7410(k)(3); CAA Sec. 107(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State by submitting an implementation plan for such State which will specify the manner in which national primary and secondary ambient air quality standards will be achieved and maintained within each air quality control region in such State." Simply put, EPA lacks discretion to decide that it would prefer a uniform national approach for Good Neighbor provisions. *Train v. Natural Resources Def. Council*, 421 U.S. 60, 79 (1975) ("The Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards of § 110(a)(2), and the Agency may devise and promulgate a specific plan of its own only if a State fails to submit an implementation plan which satisfies those standards."); *Concerned Citizens of Bridesburg v. U.S. E.P.A*, 836 F.2d 777, 780–81 (3rd Cir. 1987) (holding the Clean Air Act "left the mechanics of achieving NAAQS to the states. Section 7410(a) requires each state to formulate and submit to the EPA a SIP detailing regulations and source-by-source emissions limitations that will conform the air quality within its boundaries to the NAAQS. The SIP basically embodies *a set of choices regarding such matters as transportation,*

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[88] *See Chevron U.S.A., Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (U.S. 1984).

[89] 87 Fed. Reg. 9798, 9801, 9835 (Feb. 22,2022).

zoning and industrial development that the state makes for itself in attempting to reach the NAAQS with minimum dislocation. Because the states have primary responsibility for achieving air quality standards, the EPA has limited authority to reject a SIP."); *Commonwealth v. Environmental Protection Agency*, 108 F.3d 1397, 1410 (D.C. Cir. 1997) ("section 110 does not enable EPA to force particular control measures on the states"). Accordingly, EPA deserves no deference in any decision to prefer a nationwide FIP based on a "common core of nationwide policy judgements" over a SIP based on "a set of choices regarding such matters as transportation, zoning and industrial development that the state makes for itself."

2. EPA's decision to subject sources in upwind states to control limits stricter than the RACT level of control Congress has set for NAAQS compliance in even nonattainment areas is outside the discretion of EPA, and clearly conflicts with the structure of Title I of the Clean Air Act, the Good Neighbor provision, and the intent of Congress, and does not merit *Chevron* deference.

3. As discussed in detail throughout these comments, the many ways in which EPA analyzes and proposes to regulate non-EGUs in ways different than what has been upheld for EGUs in prior Good Neighbor rulemakings, and the various other unreasonable or arbitrary positions identified throughout these comments are not reasonable interpretations of the statute, and do not merit *Chevron* deference.

C. EPA's Consideration of Co-Benefits to Calculate Benefits of the Rule is Not Reasonable and is Arbitrary in Light of Other EPA Rulemakings

EPA justifies the costs of the Proposed Rule by accounting for not only the costs associated with ozone formation based on NOx reductions, but also based on climate impacts expected from expected co-reductions of CO2, and PM2.5 reductions based on expected co-reductions of PM2.5 and SO2.[90]

This is not reasonable or appropriate, because the statutory basis for such limits is grounded in assessing just the pollutants involved in the specific NAAQS at issue. For each NAAQS, the Good Neighbor provision provides that implementing plans may limit "any air pollutant" that contributes significantly to compliance issues with "*such national primary or secondary ambient air quality standard.*"[91] Accordingly, e.g., for the specific ozone NAAQS, the Good Neighbor

[90] E.g., Proposed Rule at 20,155; 20167; see also Regulatory Impact Analysis at 5-4 through 5-26 (incorporating PM2.5 reduction estimates when calculating health and economic benefits of the rule) & Table ES-7 through ES 10 (footnote to each admit that the "ozone benefits" in the tables actually aggregate benefits from reductions of ozone AND PM2.5) & 5-26 through 5-31 (assessing climate impacts of the rule based on CO2 co-reductions, and stating that although the EPA did not quantify benefits from CO2 reductions, EPA nevertheless took them into account as "unquantified benefits of this proposal" when evaluating the benefits of the rule; see also Data and Results for the Monetized Health Benefits Analysis as part of the Regulatory Impact Analysis.

[91] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

provision allows regulation of any pollutant that contributes to compliance issues with the Ozone NAAQS (e.g. NOx), but not pollutants unrelated to Ozone compliance (CO2, PM2.5, SO2, etc.).

Moreover, EPA's approach to "baking-in" co-benefit considerations is arbitrary because it is incompatible with EPA's current promulgated final rule assessing the appropriateness of accounting for co-reductions of pollutants other than the pollutant subject to a particular regulation.[92] When assessing the appropriateness of taking into account benefits of non-HAP reductions in the context of the Clean Air Act's HAP regulations under section 112 of the Clean Air Act, EPA found that "the EPA's equal reliance on the particulate matter (PM) air quality co-benefits projected to occur as a result of the reductions in HAP was flawed as the focus of CAA section 112(n)(1)(A) is HAP emissions reductions."[93] More specifically, "Indeed, it would be highly illogical for the Agency to make a determination that regulation under CAA section 112, which is expressly designed to deal with HAP, is justified principally on the basis of the criteria pollutant impacts of these regulations. That is, if the HAP related benefits are not at least moderately commensurate with the cost of HAP controls, then no amount of co-benefits can offset this imbalance for purposes of a determination that it is appropriate to regulate under CAA section 112(n)(1)(A)."

Although CAA Sections 112(n)(1)(A) and 110(a)(2) are separate statutory schemes, the cost/benefit analysis must be treated consistently because both treatment of cost under each provision is based on the same question: whether a given regulation is "appropriate" and "necessary." [94] Accordingly, because the Ozone NAAQS is focused on ozone reductions, any Good Neighbor implementation plan under the Ozone NAAQS should also only be considered "appropriate" if the ozone benefits are commensurate to the costs, without relying on co-benefits from PM2.5 reductions and climate considerations, since both are outside the scope of the Ozone NAAQS.

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[92] See "Proposed Rule: National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 84 Fed. Reg. 2670; see also "Final Rule: National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units—Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 85 Fed. Reg. 31,286, 31,299 (May 22, 2020) ("finalizing the determination outlined in the 2019 Proposal").

[93] 84 Fed. Reg. at 2676.

[94] *Compare* U.S. Code § 7412(n)(1)(A) ("The Administrator shall regulate electric utility steam generating units under this section, if the Administrator finds such regulation is *appropriate and necessary*"), *with* 42 U.S. Code § 7410(a)(2)(A) (providing that implementation plans for each individual criteria pollutant under Section 110 "shall" "include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be *necessary or appropriate* to meet the applicable requirements of this chapter").

D. EPA's Disregard for Demonstrations of Infeasibility Miscomprehends the Precedent EPA Relies On.

EPA makes the assertion that it is authorized to ignore "claims about infeasibility of controls" raised by any facility, citing solely to the D.C. Circuit's opinion in *Wisconsin v. EPA*.[95] But EPA mischaracterizes the D.C. Circuit decision. In *Wisconsin*, the court simply required that the deadline for upwind state compliance with Good Neighbor provision align with downwind states deadlines for compliance with a given NAAQS. In doing so, it is true that the court rejected an EPA argument that it was infeasible to require compliance with the Good Neighbor provision in a timely manner, but the discussion of "feasibility" was not about technical feasibility of whether controls would be capable of being retrofitted and or concerning whether controls could actually feasibly reduce the emissions to the extent needed. Rather, the "feasibility" issues the court and EPA discussed in that context instead concerned whether EPA had enough time and information to draft and implement required reductions in a timely manner.[96]

It is also readily apparent that the technical feasibility questions raised by the Proposed Rule's unit level emission limits are categorically different than the "feasibility" concerns discussed in *Wisconsin*, because the rule at issue in *Wisconsin* involved only statewide emission budgets and did not involve any command-and-control limits like those now proposed. Furthermore, it would be one thing if EPA simply had a statewide emission cap requiring absolute reductions in NOx, because then a facility could meet the limit by operating less if it is absolutely necessary for emissions to decrease in order to meet downwind attainment, but EPA's proposal goes beyond that, with the efficiency based lb/mmBtu limits that may make it literally impossible to comply if the proposed controls cannot feasibly reduce emissions to the extent EPA assumes due to the differences in the steelmaking process than coal fired powerplants, whereas overall emission budget reductions would still accomplish any mandate faced by EPA due to *Wisconsin* while giving facilities the flexibility to meet them in the most efficient and technically feasible manner, or in the worst case to operate less.

VIII. EPA's Decision to Deny Non-EGUs Compliance Flexibility is Arbitrary and Capricious

A. It is Arbitrary to Deny Non-EGUs Compliance Flexibility Granted to EGUs

A key component of the currently established CSAPR rule is that it provides for trading of NOx emission credits. The Proposed Rule itself recognizes that "the current CSAPR trading program structure . . . has important positive attributes, particularly with respect to the exceptional degree of compliance flexibility it can provide. . . .".[97] As described in the Proposed Rule, "[t]he trading program's option to buy additional allowances provides flexibility in the program for

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[95] Proposed Rule at 20,104 & n.242 (citing Wisconsin v. Envtl. Prot. Agency, 938 F.3d 303 (D.C. Cir. 2019)).

[96] See 81 Fed. Reg 74,504, 74,552 (Oct. 26, 2016) ("a remedy simply is not feasible *in the existing timeframe*. . . . the agency does not have sufficient information at this time to promulgate such a rule.").

[97] 87 Fed. Reg. at 20,107.

outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect, this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions." [98]

For non-EGUs, the Proposed Rule arbitrarily includes no similar flexibility. The Proposed Rule in fact includes no flexibility at all. There is no allowance for variances from EPA's "command-and-control" emission limits for facilities that cannot retrofit EPA's required pollution control equipment or achieve the extreme reductions the Proposed Rule prescribes even after installing EPA's selected technology. There is no process for submitting an alternative control strategy to EPA or for non-EGUs or the states in which they are located, to offset the emission reductions mandated by the Proposed Rule with other, more cost-effective emission reductions. There is not even an opportunity to extend deadlines if it is found that the required pollution control and monitoring equipment required by the Proposed Rule cannot be purchased and installed on the schedule mandated by EPA.

While the Proposed Rule should not be finalized in any form, if EPA does proceed with finalizing a FIP for interstate transport of ozone, it must afford compliance flexibility for all subject sources, not just EGUs. EPA should consider extending emission trading to non-EGUs so that a disproportionate burden is not placed on non-EGUs to achieve emission reductions not required of other sources. EPA should also include a process for regulated sources or affected states to petition for variances from the required emission limits and compliance schedules upon a demonstration of infeasibility or impracticality.

B. EPA's Decision to Exclude All Non-EGUs from the Emissions Trading System Arbitrarily Reverses Prior Agency Determinations Without Justification.

EPA's decision to exclude all non-EGU's from the emissions trading program is a major regulatory about-face by the agency which it neither recognizes nor confronts, impermissibly attempting to "depart from a prior policy *sub silentio*." *See FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515 (2009). EPA has consistently endorsed an emissions trading program over unit-specific limitations, and the Proposal fails to adequately justify the decision to categorically exclude non-EGUs from the trading program.

In April 2021, EPA explained that the trading program "not only encourages units to achieve the rates assumed in the budget-setting process, but to perform at even better rates where better performance can be achieved at a cost lower than the allowance price. By contrast, an implementation mechanism that provides a unit-specific emission rate would not incentivize the unit to perform better than its rate requirement."[99] EPA further stated that "unit-specific short-term emission rates pose significant implementation and rulemaking challenges," and if EPA were "to

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[98] *Id.* at 20,100.

[99] EPA Final Rule – Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, pg. 65 (published April 30, 2021).

choose to implement a unit-specific emissions rate regime for implementation, the compliance flexibility afforded by emissions trading would not be available and it would not be possible to rely on fleet average information to the same extent . . . ."[100]

Nevertheless, EPA now proposes to exclude non-EGUs from the trading program. In a mere two paragraphs, EPA seeks to justify this exclusion by asserting that if it "were to include non-EGUs in the trading program, [it] would require monitoring and reporting of hourly mass emissions . . . as [it has] for all trading programs." The Proposal therefore concludes that "applying unit-level emissions limitations . . . rather than constructing an emissions trading regime is more administratively feasible and more easily implementable at the source level . . . ." This proposed exclusion is arbitrary and capricious for a number of reasons.

First, the Proposed Rule already requires the installation of monitoring equipment for non-EGUs. The Proposal explicitly states:

> "The EPA is proposing to require each owner or operator of an affected facility that is subject to the NOx emissions limit for Iron and Steel Mills and Ferroalloy Manufacturing emissions units contained in this section to install, calibrate, maintain, and operate a CEMS for the measurement of NOx emissions discharged into the atmosphere from the affected facility. The EPA is proposing that each emissions unit will be required to conduct an initial performance test and to operate CEMS to assure compliance."[101]

Thus, EPA's rationale for excluding non-EGUs from the trading program—that including them "would require monitoring and reporting," including "CEMS (or an approved alternative method)"[102]—is internally inconsistent, arbitrary, and capricious. EPA is proposing to require iron and steel industry units subject to the Proposed Rule to install CEMS or monitoring equipment anyway.

Moreover, when EPA initiated the trading program, it provided EGUs with no less than two-and-a-half years to install monitoring equipment.[103] But EPA now appears to believe that three-and-a-half years (until the compliance deadline of 2026) is an inadequate amount of time, warranting the exclusion of non-EGUs from the trading program. EPA does not provide any reason for this shift other than to note general uncertainty as to how long it may take non-EGUs to install monitoring equipment. But "where an agency is uncertain about the effects of agency action, it may not rely on 'substantial uncertainty' as a justification for its actions."[104] "Instead, EPA must

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[100] *Id.*

[101] Proposed Rule, pg. 20,146 (emphasis added).

[102] *Id.* At 20,141.

[103] Clean Air Interstate Rule, 70 Fed. Reg. 25,161 (May 12, 2005).

[104] *Scholl v. Mnuchin*, 489 F. Supp. 3d 1008, 1036 (N.D. Cal. 2020), quoting *Greater Yellowstone Coal., Inc. v. Servheen*, 665 F.3d 1015, 1028 (9th Cir. 2011).

'rationally explain why the uncertainty' supports the chosen approach."[105] EPA's failure to justify its "depart[ure] from a prior policy" renders the decision to exclude non-EGUs from the trading program "arbitrary and capricious."[106]

Additionally, EPA's assertion that it has "require[d] monitoring . . . for all trading programs," lacks one crucial clarification. When EPA initiated the trading program, the provision requiring use of CEMS still provided a process for a "unit that does not meet the applicable compliance date" for installing monitoring equipment to "determine, record, and report substitute data"[107] in lieu of CEMS data. If EPA determines that CEMS are both necessary and appropriate (including but not limited to cost justified), EPA should likewise provide a process for providing "substitute data" in the hypothetical event that certain units are unable to install monitoring equipment by 2026 or confront and justify it decision to deny non-EGUs this ability provided to EGUs.

Finally, the assertion that unit level controls are superior for non-EGUs because they are (in some unexplained way) "more administratively feasible and more easily implementable at the source level" is fatally inconsistent not just with EPA's prior findings, <u>but with the Proposed Rule itself</u>, which elsewhere expressly finds that an emission trading program is superior to direct controls for EGUs because "trading program's option to buy additional allowances provides flexibility in the program for outlier sources that may need more time than what is representative of the fleet average to implement these mitigation strategies while providing an economic incentive to outperform rate and timing assumptions for those sources that can do so. In effect this trading program implementation operationalizes the mitigation measures as state-wide assumptions for the EGU fleet rather than unit-specific assumptions."[108]

IX. Timing of Compliance for States Linked Only to Maintenance Receptors

EPA currently subjects states linked only with maintenance receptors[109] to the same 2026 deadline EPA sets as applicable to states linked to nonattainment receptors. But as explained below, this is based on an erroneous legal assumption that all compliance must be in place by 2026, when in fact EPA retains discretion with regard to states that are not linked to any nonattainment receptors. Furthermore, the 2026 deadline should not bind states only linked to maintenance areas, or in any case, requirements should be suspended as long as the linked receptors are in attainment, with obligations triggered only if the maintenance receptors slip into nonattainment, as explained below.

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[105] *Id.*

[106] *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515-16, 129 S. Ct. 1800, 1811 (2009).

[107] Clean Air Interstate Rule, 70 Fed. Reg. 25,161, 25,355 (May 12, 2005).

[108] Proposed Rule, pg. 20,100.

[109] I.e., Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin and Wyoming. See Air Quality Modeling TSD at D-1 to D-11.

The entire basis for the EPA selecting the 2026 ozone season compliance deadline for non-EGUs in the Proposed Rule is *Wisconsin v. EPA*'s requirement that EPA to tie upwind-State's Good Neighbor compliance to downwind-State's nonattainment deadlines or the earliest possible time thereafter, paired with EPA's finding that the 2026 ozone season is the first possible season during which the non-EGU limits proposed in the Proposed Rule can feasibly go into effect (which is aligned with the August 3, 2027, attainment date for areas classified as Serious nonattainment under the 2015 ozone NAAQS).[110]

But *Wisconsin* merely required "upwind States to eliminate their significant contributions in accordance with the deadline by which downwind States must come into compliance with the NAAQS."[111] And notably, this only requires linkage of deadlines when it is required for a downwind state to come into attainment, meaning that it does not govern maintenance receptors trending toward full attainment, such as the Brazoria County, TX receptor which EPA models to be in attainment before 2026 (i.e., where the receptor is in attainment, albeit maintenance, and thus the downwind state is in compliance with the NAAQS at that receptor such that no upwind reductions are needed by any specific time).

Accordingly, EPA's application of the 2026 deadline to states linked only to improving maintenance receptors (e.g., Arkansas, Minnesota, Mississippi, Oklahoma, Wisconsin, Wyoming) is legally erroneous, since EPA's current rationale is that such a deadline is mandated by *Wisconsin v. EPA*'s, when in fact it is not, and thus EPA must provide a discretionary rationale if it wishes to subject such states to the same deadline as states linked to nonattainment receptors.[112]

Additionally, it would be consistent with *Wisconsin v. EPA* to suspend applicability of the Proposed Rule's limits to Arkansas and Mississippi so long as the Brazoria County, TX receptor is in attainment by 2026, and EPA should do so given the specific characteristics and trend of the Brazoria receptor. As explained below, to truly link upwind state compliance deadlines to downwind compliance deadlines, EPA should suspend Good Neighbor compliance deadlines for states solely linked to a maintenance receptor unless and until such a maintenance receptor slips into nonattainment. After all, once the Brazoria receptor is no longer in nonattainment, Texas' obligations "to submit attainment demonstrations and associated RACM, RFP plans, contingency measures for failure to attain or make reasonable progress, and other planning SIPs related to attainment of the ozone NAAQS for which the determination has been made, *shall be suspended* until such time as: The area is redesignated to attainment for that NAAQS, at which time the requirements no longer apply; or the EPA determines that the area has violated that NAAQS, at which time the area is again required to submit such plans." [113] Thus, for example, it would be

[110] Proposed Rule at 20,099-100.

[111] *Wisconsin v. EPA*, 938 F.3d 303, 313 (D.C. Cir. 2019).

[112] See *Prill v. N.L.R.B*, 755 F.2d 941, 942 (D.C. Cir. 1985) (concluding that where an agency erroneously assumed that a determination was mandated and outside of the agency's discretion, the determination "stands on a faulty legal premise and without adequate rationale.").

[113] 40 CFR § 51.1318.

incongruous to require upwind emission reductions in 2026 based solely on contributions to the Brazoria County, TX if Texas' obligations with respect to the same receptor are suspended based on this receptor measuring in attainment by that time. This is especially justified for Arkansas given the upcoming closures of NOx sources like the White Bluff plant by 2028, leading to even further NOx reductions from Arkansas than taken into account by EPA.

Specifically for the Brazoria County, Texas receptor it is currently designated as marginal nonattainment, but EPA has proposed to redesignate it pursuant to CAA section 181(b)(2)(A)(i) and 40 CFR 51.1303 based on failure to attain by the deadline for marginal nonattainment, thus requiring the receptor to be attain the 2015 Ozone NAAQS by the next deadline of "no later than 6 years after the initial designation as nonattainment, which in this case would be no later than August 3, 2024"[114] EPA's modeling as part of the Proposed Rule models the Brazoria receptor reaching attainment (albeit maintenance status) by 2023 or before, expecting the receptor no longer be in nonattainment, such that Texas' obligations would be expected to be suspended with respect to that receptor at that time in 2024, and if Texas meets that attainment deadline as anticipated by EPA, the receptor could even be officially redesignated as no longer nonattainment before 2026 when the Proposed Rule's non-EGU limits are proposed to take effect. Thus, given the particular circumstances of the Brazoria receptor, including its specific deadline for attainment and EPA's modeling in the Proposed Rule, EPA should suspend applicability of the Proposed Rule's non-EGU limits on states linked solely to the Brazoria receptor so long as the Brazoria receptor is in attainment by the appropriate deadline. If, however, the receptor slips back into nonattainment after that time, then any necessary Good Neighbor provisions in states linked to that maintenance receptor would be triggered, with the provisions EPA currently proposes to be effective 2023 to instead become effective in the event the Brazoria receptor slips into nonattainment, with the provisions currently proposed for 2026 ozone season becoming effective three years from the date the Brazoria receptor actually slips to nonattainment.

X. Unreasonable Limitations on Public Comment

A. EPA Should Allow More Time for Public Comment

EPA is proposing to impose unprecedented unit-level emissions limitations on a wide array of industries and jurisdictions. There was virtually no effort to gather industry input prior to regulation, and as discussed above, little more effort has been made to review and incorporate data and comments from the states.

The Proposed Rule itself covers 181 pages, and the record still has numerous omissions. Yet EPA has provided only 11 weeks for public comment. While U. S. Steel appreciates the extension that extended the initial deadline by two weeks, this is still not enough time for proper public input on such an extensive attempt at regulation, and as noted throughout these comments, does not provide the time to perform the various analyses EPA failed to perform as part of the

[114] "Determinations of Attainment by the Attainment Date, Extensions of the Attainment Date, and Reclassification of Areas Classified as Marginal for the 2015 Ozone National Ambient Air Quality Standards" 87 Fed. Reg. 21,842, 21,850 (April 13, 2022).

Proposed Rule, including but not limited to facility- and unit-specific contribution modeling and facility- and unit-specific feasibility assessments, both of which must be prerequisites to any exercise of EPA authority under the Good Neighbor provision. To ensure an adequate process for public input, EPA must allow time for interested parties to analyze EPA's data and prepare supplemental information and comments.

B. EPA's Denial of U.S. Steel's Request for Additional Time for Comments is Unjustified.

U. S. Steel separately requested an additional extension (EPA-HQ-OAR-2021-0668-0244), which EPA denied on June 17, 2022. EPA's denial essentially relies on two grounds to deny the extension request. First, EPA relies on the claim that it must not further extend comments because EPA has an obligation to move "as expeditiously as practicable." But as noted in the State of Arkansas' comments on EPA's proposed denial of Arkansas' proposed Good Neighbor SIP provisions for the 2015 Ozone NAAQS, EPA delayed evaluation of underlying state SIP submissions and modeling for more than a year.[115] It is unreasonable for EPA to delay any evaluation of Good Neighbor provision requirements and then use that very delay as a reason to prevent the public from having adequate time to evaluate and comment on EPA's proposed approach. EPA's other rationale is that EPA provided some of the materials underlying the Proposed Rule prior to the formal publication of the Proposed Rule in the Federal Register. But this does not address the facts that (1) EPA's choice to pursue unit specific reductions entails requires detailed facility- and unit-specific modeling and engineering studies to evaluate contribution to downwind receptors and feasibility, availability, and cost of proposed controls, which can take months to complete in the detail necessary to fully evaluate the Proposed Rule's unprecedented limits that have never been achieved by any known source to date; and (2) that information needed to evaluate the Proposed Rule was not provided until after the Proposed Rule was published in the Federal Register. Simply re-running the CAMx modeling can take months and EPA took several weeks to provide the modeling data referenced in the Proposed Rule upon request, not providing the modeling files needed to adequately comment on EPA's modeling until over a month after publication of the Proposed Rule.

C. EPA Must Reissue the Rule For Additional Comment if Substantive Changes in Approach Are Made in the Final Rule.

The rulemaking procedures at section 307(d) of the CAA specifically require that a proposed rulemaking must "include a summary of—(A) the factual data on which the proposed rule is based; (B) the methodology used in obtaining the data and in analyzing the data; and (C) the major legal interpretations and policy considerations underlying the proposed rule" and "All data, information, and documents referred to in this paragraph on which the proposed rule relies shall be included in the docket on the date of publication of the proposed rule."[116] Furthermore,

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[115] See Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality, on EPA-R06-OAR-2021-0801-0001, at 3-4 (April 22, 2022).

[116] 42 U.S.C. § 7607(d)(3).

any final "promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation."[117] Relatedly, EPA has "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule" including an obligation to "explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated."[118]

Accordingly, it would be unlawful for EPA to make any revisions to the Proposed Rule that are not supported by the data in the docket, including but not limited to subjecting additional units to the Proposed Rule where the feasibility, cost effectiveness, and significance to downwind receptors is not included in the docket supporting the Proposed Rule, absent a new proposed rule providing the opportunity for public comment on the basis for any such newly proposed changes. Furthermore, it would be arbitrary for EPA to reverse any of the determinations it has made in this Proposed Rule, such as by including emission units or sources not currently proposed to be included in the Proposed Rule or the draft regulation accompanying the Proposed Rule or imposing a trading system or other controls rather than the current proposed controls, without first re-issuing such changes in the form of a new proposed rule for additional public comment.

XI. EPA Should Reconsider the National Applicability of the Proposed Rule.

EPA proposes to find that this proposed action, "if finalized, would be 'nationally applicable' within the meaning of CAA section 307(b)(1)" or, in the alternative, that "this action is based on a determination of 'nationwide scope or effect" within the meaning of CAA section 307(b)(1)." This is based on EPA's finding that the "proposed action applies a uniform, nationwide analytical method and interpretation of CAA section 110(a)(2)(D)(i)(I) across these states, and the proposed rule is based on a common core of legal, technical, and policy determinations (as explained in further detail in the following paragraph). For these reasons, this proposed action is nationally applicable."[119].

EPA's proposal is not well founded. The Proposed Rule notes that if finalized, it will "implement the good neighbor provision in 26 states, spanning 8 EPA regions and 10 federal judicial circuits."[120] This is only because EPA has aggregated several rulemakings into the Proposed Rule. The FIP applies on a state-by-state basis. That EPA failed to make the state-specific assessments required for a proper review of each State's SIP and replacement with a FIP

[117] 42 U.S.C. § 7607(d)(6)(C).

[118] *National Lime Ass'n v. E. P. A.*, 627 F.2d 416, 433 (D.C. Cir. 1980) (in the context of a new source performance standard rulemaking procedure subject to 42 U.S.C. § 7607(d), holding that "an initial burden of promulgating and explaining a non-arbitrary, non-capricious rule rests with the Agency and we think that by failing to explain how the standard proposed is achievable under the range of relevant conditions which may affect the emissions to be regulated, the Agency has not satisfied this initial burden."); *see also Nat. Res. Def. Council v. EPA*, 755 F.3d 1010, 1023 (D.C. Cir. 2014) ("EPA retains a duty to examine key assumptions as part of its affirmative burden of promulgating and explaining a nonarbitrary, non-capricious rule and therefore EPA must justify that assumption even if no one objects to it during the comment period.") (citation, internal question marks, and ellipses omitted).

[119] Proposed Rule at 20,168

[120] Proposed Rule at 20,168.

is not a justification for stripping the applicable regional courts of jurisdiction over what are inherently state-specific issues.

EPA's alternative approach, to find that the "proposed action is based on multiple determinations of nationwide scope or effect for purposes of CAA section 307(b)(1)" is similarly inadequate. Using a "common core of statutory and case law analysis, factual findings, and policy determinations concerning the transport of ozone-precursor pollutants from the different states subject to it, as well as the impacts of those pollutants and the impacts of options to address those pollutants in yet other states"[121] to find that a state-specific rule has national applicability is to find that the exception swallows the rule. Most state-specific rules EPA promulgates are based on a "common core of statutory and case law analysis, factual findings, and policy determinations." This is part of what prevents EPA from acting arbitrarily and capriciously. If this were sufficient to make a state-specific rule nationally applicable, then almost all EPA rulemaking would be forced into the D.C. Circuit for judicial review.

XII. Miscellaneous Comments, and Responses to EPA Requests for Comment

A. Applicability Provisions Require Clarification:

There are multiple aspects of the Proposed Rule's applicability which should be clarified before proceeding to final rule.

1. First, it appears that the Proposed Rule will only cover emission units which are individually under 100 tons per year in the case of facilities with a Basic Oxygen Process Furnace, for which the Proposed Rule would aggregate emissions from the "BOF Shop" for purposes of determining the Proposed Rule's applicability to units in the "BOF Shop."[122] EPA should further clarify what is unique about BOF operations that require them to be aggregated for applicability purposes rather than each emission unit being subject to a 100 tpy applicability threshold like other furnaces. Furthermore, because the Proposed Rule does not contain any NOx emission standard applicable to a BOF Shop as a whole, and because the activities listed as constituting a BOF appear to include activities that are not one of the furnace types regulated under the Proposed Rule (e.g. hot metal transfer and desulfurization), and because the processes noted as constituting a BOF Shop do not appear to be the type of activities that each have separate stacks, the final rule should clarify how a BOF Shop will demonstrate compliance with the emissions in the rule (e.g., if all emissions in a BOF Shop are vented through the same venting system, then a BOF Shop should be able to aggregate the individual limits of any units within the BOF Shop in making its compliance demonstration, or should be subject to a separate overall limit for a BOF Shop).
2. The definition of a reheat furnace as currently drafted is overly vague and should be amended to match the reheat furnaces (and related definitions) on which EPA's review was

[121] Proposed Rule at 20,168

[122] Proposed Rule at 20,181.

based. The current definition of a reheat furnace in the Proposed Rule is "a furnace used to heat steel product to temperatures at which it will be suitable for deformation and further processing."[123] This definition does not define what counts as "steel product" (e.g., does it include only products that have already been manufactured into some form prior to being introduced to a reheat furnace, or does it include steel that has never left the original production process, such as hot steel coming directly from a connected casting process which has not yet been formed into a definitive product). When setting a limit for reheat furnaces in the Proposed Rule, EPA expressly relied on the Ohio RACT limit for reheat furnaces.[124] Ohio's applicable definition (i.e. defining the universe of units the RACT limit EPA relied on applied to) provides that " 'Reheat furnace' means a furnace in which metal ingots, billets, slabs, beams, blooms and other similar products are heated to bring them to the temperature required needed for hot-working."[125] This definition is also consistent with the various permits that EPA looked at when setting a limit for a reheat furnace.[126] EPA should likewise clarify its definition of reheat furnace to match the definition used by Ohio or otherwise make the definition more clearly limited to the types of units and limits EPA considered in setting the emission limits for reheat furnaces in the Proposed Rule. This clarification should more clearly differentiate a reheat furnace, which handles pre-made intermediate products, from something like a tunnel furnace that merely maintains and equalizes the temperature of raw already-hot-slabs while in transit from a caster to some other operation like a rolling mill. Any other approach that broadens applicability of the definition of reheat furnace beyond the type of sources EPA reviewed in setting its proposed emission limit would be arbitrary, since it would be unreasonable and arbitrary to regulate a unit without any reasoned basis for subjecting it to that emission limit.

3. EPA should also resolve the current discrepancy concerning the basis for the 40% reduction EPA is requiring at reheat furnaces. The Proposed Rule states that a 40% reduction is assumed based on installation of SCR,[127] whereas the underlying Non-EGU Sectors TSD states that the 40% reduction is instead based on low-NOx burners, not including SCR.[128] Either way, EPA must also provide additional rationale for the reductions, because assuming reductions based solely on the basis of low NOx burners may be inconsistent with the fact that the permit limits EPA reviewed in setting this limit, specifically Sterling Steel, already had low-NOx burners installed, and thus it may not be reasonable to assume

[123] Proposed Rule at 20,181.

[124] Non-EGU Sectors TSD at 42.

[125] OAC 3745-110-01 (35).

[126] See Non-EGU Sectors TSD at 42, pointing to permit limits at Sterling Steel, Charter Steel, and United States Steel Lorain Tubular Operations, each of which specifies a premade product that the reheat furnace accepts as an input, i.e. a "Billet" reheat furnace at Sterling Steel, a "Bar Mill" reheat furnace at Charter Steel. Likewise, the US Steel Lorain Tubular facility reheat furnaces handle products made elsewhere as inputs and are not handling raw product.

[127] Proposed Rule at 20,145.

[128] Non-EGU Sectors TSD at 43.

additional emission reduction since those controls are already in place. By contrast, if the reductions are based on assumption of SCR feasibility, then EPA must detail why EPA believes SCR to be feasible and cost effective for such units, which it has not done specifically to reheat furnaces.

4. The Proposed Rule should clarify what if any limit is applicable to galvanizing furnaces. The Non-EGU Sectors TSD mentions galvanizing furnaces several times, often in the same context as annealing and reheat furnaces, such as when EPA identifies a Wisconsin NOx RACT limit of 0.08 lb/mmBtu which applied to reheat, annealing and galvanizing furnaces.[129] Furthermore, the technical support document also distinguishes between reheat, annealing, and galvanizing furnaces as separate types of units.[130] However, the final rule includes different limits for annealing furnaces (0.06 lb/mmBtu) and reheat furnaces (0.05 lb/mmBtu), and does not include a separate galvanizing furnace limit. Accordingly, EPA should clarify whether galvanizing furnaces are intended to be included under the limits applicable to reheat furnaces, annealing furnaces, or neither, including appropriately detailed rationale.

B. The Proposed Rule's Emission Unit Specific Limits and Monitoring Requirements Will Not be Practicably Enforceable for Units that Lack Unit Specific Stacks.

The Proposed Rule appears to assume that each different unit is stacked such that its emissions could be disaggregated from other units, but that is not the case. Some units share a joint stack, some have multiple stacks, and some are so minor as to not be stacked. Accordingly, the Proposed Rule, if finalized, must allow for flexibility in demonstrating compliance with associated emission limits.

For example, the Proposed Rule establishes separate limits for EAFs, LMFs, and ladle/tundish preheaters. But LMFs and ladle/tundish preheaters are relatively small sources of emissions at the U. S. Steel's BRS facility (and future EV facility) are not vented through a separate stack. Rather, the EAF and LMF and other small units in the melt shop such as ladle/tundish preheaters are typically hooded and exhausted through the same canopy system to the baghouse where the joint emissions then vent to the baghouse and the primary exhaust stack. Accordingly, it is not possible to separately monitor preheater, LMF, and EAF emissions with CEMS, or to verify separate emission limits, since any compliance demonstration, whether by CEMS or stack testing, will necessarily be based on a joint measurement of preheater, LMF, and EAF emissions. This is reflected in BRS's and EV's current air permits, which provides a joint lb/hr emission limit for an LMF and EAF combined. Accordingly, to the extent the final rule still imposes command-

[129] Non-EGU Sectors TSD at 42.

[130] Non-EGU Sectors TSD at 26 ("Annealing involves a supplemental heating process to change the hardness properties of the final steel produced and ensure homogeneity. The galvanizing process coats iron or steal in a coating of molten zinc to protect and seal, limiting rust and corrosion. Reheat furnaces are used in hot rolling mills to heat steel slabs for rolling into sheets").

and-control limits for individual emission units, the final rule should take this reality into account by either creating a joint limit for an EAF, LMF and preheaters combined, or by allowing EAF, LMF, and preheater emissions to be aggregated for purposes of any compliance demonstration of their combined limits. Furthermore, EAFs are the only units that are over 100 tpy at U. S. Steel BRS and EV facilities subject to the Proposed Rule, and thus the Proposed Rule would not apply to LMF and preheaters, at least at these facilities. Thus, EPA should clarify how compliance with the proposed emission limits for EAFs will be demonstrated, given the fact that any CEMS installed on an EAF stack will reflect emissions from other units which may not even be subject to limits under the Proposed Rule.

By contrast, other units like the tunnel furnaces at the BRS facility have as many as five stacks per furnace due to the physical length of the tunnel transportation process. It cannot be assumed that these could be redesigned to a single stack, because due to design and overlapping influence within the tunnel furnaces the atmospheric conditions as it relates to the burners can potentially have different requirements for one stack versus another and could adversely affect the facility and steel quality. Accordingly, when performing cost estimates to determine the appropriateness of any efficiency limits EPA proposes for such furnaces, EPA must take into account the cost of multiple SCR and CEMS rather than assuming that a single CEMS and SCR could be installed on such units. For clarity, these units have less than 100 tpy NOx potential emissions at the U. S. Steel BRS facility, and as noted in the previous comment, it is unclear whether a tunnel furnace designed solely to maintain temperatures of hot-steel would in any-case be covered by the Proposed Rule.

Finally, annealing units can vary greatly in size and amenability to controls. For example, the batch annealing furnaces at the U. S. Steel BRS facility (and the EV facility under construction) entail such small amounts of emissions that they are not stacked and thus cannot be subjected to unit specific SCR, much less CEMS.

C. Efficiency Based Form of Proposed Emission Limits is Unreasonable

EPA provides no persuasive justification for imposing efficiency limits (i.e., lb/mmBtu limits) instead of emission limitations tied to the actual reductions needed to eliminate an upwind state's significant contribution. EPA's statutory authority under the Good Neighbor provision is solely intended to be used to reduce an absolute "amount" of emissions for the tailored purpose of achieving downwind NAAQS attainment[131], and is not an appropriate means to force industrywide standards of performance; if the efficiency standards preferred by EPA can be justified, then EPA can pursue that objective through NESHAP and NSPS standards. Furthermore, EPA's modeling relied on estimates of tons of reductions expected throughout each state, and EPA's compliance method is a CEMS, both of which are directly linked to absolute emissions, rather than emission efficiency. Finally, mandating efficiency-based limits arbitrarily and unreasonably eliminates the option for affected facilities to achieve any required emission reductions during ozone season through reduced operations, which could be just as effective at achieving any reductions needed

[131] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

to achieve any obligations under the Good Neighbor provision. A lb/mmBtu limit puts affected facilities, especially those with higher-than-average retrofit costs in a challenging situation, forced to choose between infeasible costs, or being shut down altogether. By contrast, limits like those that EPA has proposed in the past which only require statewide reductions by the amount emissions modeled to eliminate an upwind state's significant contribution would at least provide owners of such facilities with a tenable option of reducing emissions through reduced utilization during ozone season short of complete shutdown.

D. Unit Specific Nature of Limits Fails to Consider Alternate Emission Reductions

The unit specific nature of the proposed efficiency limits eliminates facility flexibility in reducing overall NOx emissions in more technically feasible and cost-effective ways. Although the Proposed Rule continues to grant EGUs some limited flexibility in figuring out how best to reduce emission to meet limits (which in some cases includes complete facility shutdown), the Proposed Rule robs non-EGUs of the same flexibility. Different facilities face different design and operational limitations, and the operators of each facility are in the best position to assess how to maximize emission reductions while minimizing process impacts. For example, in cases where installation of controls on an applicable furnace is not feasible, facilities should instead have the flexibility to achieve the same level of emission reductions through other means, for example a facility may still have the option of low NOx optimizations on units that would otherwise not be subject to the Proposed Rule, such as furnaces or boilers that are not of sufficient size to be included under the Proposed Rule.

E. Climate Change is Not Carte Blanche to Tighten Regulations and NAAQS Without Notice and Comment

EPA makes a generalized appeal to climate change as an excuse to find that Arkansas, Mississippi, and Wyoming are not overcontrolled by the Proposed Rule, despite EPA's models suggesting they are overcontrolled, because "future ozone concentrations and the formation of ground level ozone, may be impacted by climate change in future years," and relying on uncertainty rather than even attempting to model any climate change effect.[132] But "where an agency is uncertain about the effects of agency action, it may not rely on 'substantial uncertainty' as a justification for its actions. Instead, it must 'rationally explain why the uncertainty' supports the chosen approach."[133] And handwaving about uncertainties associated with climate change is not an excuse for increasing control stringency by overcontrolling emissions under the Good Neighbor provisions of the Clean Air Act, which are focused solely on NAAQS, absent proper regulatory and statutory authorization.[134]

[132] E.g., Proposed Rule at 20,099.

[133] *Scholl*, 489 F. Supp. 3d at 1036.

[134] To the extent EPA is attempting to use climate change considerations to make the 2015 Ozone NAAQS more stringent without going through the rulemaking process to revise the 2015 Ozone NAAQS. Any attempt by USEPA to do so in the context of the Proposed Rule would not be consistent with EPA legal obligations under the CAA.

F. It Would be Arbitrary for EPA to Not Include Waste Incinerators in the Final Rule If Other Non-EGUs Are Included

The current draft of the Proposed Rule does not propose to regulate (1) EGUs less than or equal to 25 MW, (2) solid waste incineration units, and (3) cogeneration units, each of which, just like the Iron and Steel industry and all other non-EGUs, have traditionally been excluded from EPA's interstate air transport programs. [135] Accordingly, any potential emission reductions from such facilities were not included when EPA estimated state-by-state potential NOx reductions under the Proposed Rule. [136] But EPA also requested comment on whether these must be included, and specifically noted that EPA is "considering whether to include emissions limitations for solid waste incineration units" in the Final Rule.[137]

It would be arbitrary for EPA to require reductions at the proposed non-EGUs, but not include waste incinerators. By EPA's own analysis, such waste incinerators emissions can be an order of magnitude larger than the applicability limits EPA is using to subject other industries like steel mills to command-and-control limits.[138] The questions EPA requests comment on when EPA considers whether to include waste incinerators in the final rule are generally valid questions (e.g., feasibility and cost effectiveness of controls). But EPA's resulting position is incorrect.

For example, there are potentially many such units in Arkansas, including units with permitted NOx emissions at least as high as steel industry units, and far closer to the Brazoria TX receptor than U. S. Steel's BRS and EV facilities.[139] In the Proposed Rule, EPA seeks to impose emission limits on non-EGUs such as EAFs without providing any analysis of technical feasibility

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[135] Proposed Rule at 20,084.

[136] Non-EGU Screening Assessment at 1 n.1.

[137] Proposed Rule at 20,084.

[138] Non-EGU Sectors TSD at Table 8.

[139] The following facilities, are not an exclusive list, but includes various incineration facilities under NAICS codes 562213(Solid Waste Combustors and Incinerators) or 562211 (Hazardous Waste Treatment and Disposal): Elemental Environmental Solutions LLC, Arkadelphia, 1016-AOP-R15, (245.7tpy NOx), https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1016-AOP-R15.pdf; Clean Harbors LLC, El Dorado, 1009-AOP-R24 (535.7tpy NOx), https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1009-AOP-R24.pdf. Furthermore, the following facilities are registered under General Air Permit for Title V Air Curtain Incinerators, which permits up to 30.6 tpy of NOx based on up to 15,300 tons of waste incinerated at the air curtain incinerator per rolling 12-month period (https://eportal.adeq.state.ar.us/webfiles/Air/General%20Permits/2370-AGP-000.pdf): City of Jonesboro - Yard Waste Facility (6.75 tons burned per hour); City of Dardanelle (4 tons per hour burned); Woodson Incorporated, Mabelvale (8 to 10 tons burned per hour); City of Blytheville Public Works (3 to 5 tons burned per hour); Wise Excavation LLC, Paron (8 tons burned per hour); Abide Farms, LLC, Little Rock (7 tons burned per hour); American Composting, Inc., North Little Rock (7 tons burned per hour); R. E. C. Transport, Inc., Dardanelle (7 tons burned per hour); Alternative Waste Management LLC., Mayflower (9 tons burned per hour); Arkansas Department of Transportation, Paragould (0.125 tons burned per hour); Custom Wood Recycling, Inc., Centerville (12 tons burned per hour); City of Wynne Air Curtain Incinerator (10 tons burned per hour); Columbia County Landfill, Magnolia (unspecified throughput); City of Beebe (7.5 tons burned per hour); Dale Payne - P & P Trucking, Casa (8 tons burned per hour); Moore's Dozer Service, Glenwood (9 tons burned per hour).

or cost effectiveness in the record. Yet for solid waste incineration units, EPA is proposing to use those very same factors to potentially exclude waste incinerators. If waste incinerators are excluded on such grounds, EAFs, and the many other units EPA failed to analyze for technical feasibility or cost feasibility must also be exempted. In addition, it is worth noting that any decision by EPA in the final rule to include such units (e.g., EGUs less than or equal to 25 MW, solid waste incineration units, and cogeneration units), would require EPA to perform a reanalysis of overcontrol, since including such units without adjusting the required control limits at other facilities could further exacerbate overcontrol resulting from the Proposed Rule.

G. Controls Will Only be Run on a Seasonal Basis

EPA requested comment on whether any controls installed in order to meet the limits in the Proposed Rule would be run on an annual basis.[140] As a general rule, post combustion controls like SCR will not be operated year-round. As noted above, facilities will only run post-combustion NOx controls during the ozone season when required to and will otherwise limit their use due to the high O&M cost associated with operation of the SCR, and in order to attempt to extend the life of the catalyst given the high cost of replacing the catalyst and how quickly the catalyst can be deactivated under the process characteristics of metal furnaces. Low NOx burners, the other hand, would be operated on a year-round basis since they are integrated into the combustion process.

H. Alternatives to CEMS

EPA requested comment on alternatives to CEMS for ensuring compliance.[141] There are many alternatives to CEMS. For boilers and burner tips, especially, vendor guarantees and known engineering emission factors for natural gas combustion can be used to simply and far more cost effectively track emissions based on simply tracking natural gas usage/throughput. This method may also work for furnaces where NOx emissions derive primarily from coal or natural gas combustion. For any other sources whose NOx emissions cannot be simply derived by tracking natural gas or coal throughput, stack testing should be available as an alternative means of compliance.

More fundamentally, EPA has not demonstrated that CEMS are necessary and appropriate as a means of tracking emissions for non-EGUs. The authority to require any monitoring device must be justified under 42 U.S. Code §7410(a)(2)(B), which states that an implementation plan shall "provide for establishment and operation of *appropriate devices*, methods, systems, and procedures *necessary to*—(i) monitor, compile, and analyze data on ambient air quality." In the past, EPA has required CEMS under Good Neighbor provision implementation plans on the rationale that such precise continuous measurements are necessary when implementing an emission trading program, because as EPA puts it "[t]his type of consistent and accurate measurement of emissions is necessary to ensure each allowance actually represents one ton of emissions and that one ton of reported emissions from one source would be equivalent to one ton

[140] Proposed Rule at 20,141.

[141] Proposed Rule at 20,146.

of reported emissions from another source."[142] But the Proposed Rule expressly decides not to implement a trading program, instead purporting to opt for unit specific performance limits for non-EGU emission units. Moreover, EPA did not even include the cost of CEMS in its cost analysis.[143] Accordingly, EPA has failed to justify both why CEMS are "appropriate" and why they are "necessary" in this wholly different context of unit specific performance rates, especially in light of the fact that other programs (NSPS, NESHAP, PSD, etc.) merely require initial performance testing and periodic confirmatory testing to verify unit specific performance limits, and that EPA wholly fails to provide any persuasive differentiation here in the absence of emission trading.

XIII. The Proposed Rule Endangers National Security by Failing to Consider the Steel Industry's Critical Role in Our National Security and Infrastructure:

A 2017 Presidential Memorandum recently acknowledged that "core industries such as steel" as "critical elements of our manufacturing and defense industrial bases."[144] As a result of the Memorandum, the Department of Commerce initiated an investigation into the effect of steel imports on United States National Security and found that domestic steel production is "essential" for national security applications.[145] This Investigation led to many key findings that the EPA should consider as it evaluates how to effectuate the requirements of the Good Neighbor provision in a reasonable manner.

"[A]cross decades and Administrations, there has been consensus that domestic steel production is vital to national security."[146] "National security" under Section 232 of the 1962 Trade Expansion Act includes both 1) national defense and 2) critical infrastructure needs.[147] Domestic steel production is vital for both. For example, the Department of Defense requires steel to create weapons and other systems needed for our nation's defense.[148]

[142] Proposed Rule at 20,141 (citing 75 FR 45325 (August 2, 2010)).

[143] Non-EGU Screening Assessment at 4 ("The costs do not include monitoring, recordkeeping, reporting, or testing costs.").

[144] DCPD-201700259 - Memorandum on Steel Imports and Threats to National Security, § 1 (Apr. 20, 2017) (available at https://www.govinfo.gov/content/pkg/DCPD-201700259/pdf/DCPD-201700259.pdf).

[145] U.S. Dep't. of Commerce, *The Effect of Imports of Steel on the National Security: An Investigation Conducted Under Section 232 of the Trade Expansion Act of 1962*, (hereinafter, "2018 Investigation"), Jan. 11, 2018 (available at https://www.commerce.gov/sites/default/files/the_effect_of_imports_of_steel_on_the_national_security_-_with_redactions_-_20180111.pdf).

[146] *Id.* at p. 24.

[147] *Id.* at p. 13–17, 23 (concluding that domestic steel production is essential for national security); *see also* 19 U.S.C. § 1862 (Section 232 of the Trade Expansion Act of 1962).

[148] 2018 Investigation at p. 24.

Presidential Policy Directive 21 ("PPD-21") also designates sixteen "critical infrastructure sectors," most of which use steel in high volumes.[149] This includes chemical production, communications, critical manufacturing, dams, energy, food production, nuclear reactors, and transportation, water, and wastewater systems. To support these critical infrastructure sectors, the American Society of Civil Engineers estimated that the United States must invest $4.5 trillion in infrastructure by 2025.[150] Steel production is crucial to these goals.

An important consideration to maintaining national security is ensuring that there is sufficient "surge capacity" within the industry, as explained by the Department of Commerce, "it is the ability to quickly shift production capacity used for commercial products to defense and critical infrastructure production that provides the United States a surge capability that is vital to national security, especially in an unexpected or extended conflict or national emergency."[151]

But as written, the Proposed Rule blinks these realities in ways that would have potentially catastrophic consequences for the economy and national security. Even assuming that it was possible to meet the Proposed Rule's unprecedented command-and-control limitations on NOx, installing the required control technologies will cause at least temporary closures of iron and steel facilities all around the nation all at once. "Even temporary idling of steel plants threatens the U.S. steel industry" because of the "significant financial costs with re-opening a steel mill."[152] Halting production can also cause a mill to lose workers, which affects the mill's capacity to produce steel going forward.[153] This often leads to additional costs, such as "specialized worker training and production ramp-up" while mills attempt to re-fill their workforce.[154] And that is the best case scenario; if these newly proposed limits are not feasible, and/or not able to be achieved cost effectively, mills could be forced to permanently close. Even if the new limits are attainable by some facilities, the Proposed Rule's inflexible and uniform command-and-control mandate fails to consider facility specific feasibility and cost variability and thus will likely result in permanent closures, crippling U.S. surge capacity.

Employment and local economies are likewise negatively affected when steel mills are closed, even on a temporary basis. Workers often find other occupations, steel mills to work at, or they remain indefinitely unemployed.[155] If a closure lasts a significant amount of time, workers may lose some of the specialized skills needed for performance. This loss of workers, jobs, and

[149] PPD-21 can be viewed at https://obamawhitehouse.archives.gov/the-press-office/2013/02/12/presidential-policy-directive-critical-infrastructure-security-and-resil.

[150] 2017 Infrastructure Report Card, American Society of Civil Engineers, https://www.infrastructurereportcard.org/wp-content/uploads/2016/10/2017-Infrastructure-Report-Card.pdf.

[151] 2018 Investigation at p. 55-56.

[152] 2018 Investigation at p. 34.

[153] *Id.* at 35.

[154] *Id.*

[155] *Id.*

skills causes substantial difficulties to the steel industry, as recruitment is "typically not easy."[156] And any further workforce constriction would be especially impactful because workforce experience in the iron and steel sector are already diminished.

Further, U.S. steel producers already experience higher production costs than those in other areas of the world. This is, in part, because of environmental and regulatory expenses.[157] For example, prices for hot-rolled steel coil have been higher in the United States than in other countries since 2010.[158] These higher costs incentivize foreign importation of steel, which damages steel production in the United States.

The Proposed Rule will cause iron and steel facilities to temporarily shut down while they attempt to comply with the proposed limits that have never been achieved in practice at any similar units, and thus, even if feasible, will almost certainly result in downtime as facilities and control devices are redesigned and tested. EPA's proposed compliance deadline of the 2026 ozone season risks mass temporary closures of steel mills across the country and across regions. And the supply chain disruptions arising from Covid and subsequent economic conditions, which EPA has not accounted for in setting compliance deadlines, feasibility, or cost analyses, will exacerbate the disruptions to operations that would be caused by these retrofits even in the best of times. This will hinder much of the aforementioned categories: domestic steel production will slow, local economies will be hurt, costs will rise, and the industry may lose skilled workers. Overseas imports of steel will necessarily increase, assuming there is availability. In addition, it is well known fact that steel producers in the United States have far less emissions than most sources overseas that would have to be relied on to make up for the capacity drop in domestic steel production caused by the Proposed Rule.[159] EPA must consider these critical issues as it assesses how to reasonably give effect to the Good Neighbor provision, including taking care in evaluating whether it is actually necessary to regulate the iron and steel industry in order to achieve the reductions needed to satisfy the Good Neighbor provision, and if so whether there are measures with more flexibility (including emission trading, and extended compliance deadlines) rather than rushing into draconian command-and-control measures without any evaluation of facility specific feasibility. Failure to do so threatens to jeopardize our nation's steel industry, infrastructure, and national security.

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[156] *Id.*

[157] *Id.* at p. 33.

[158] *Id.* at p. 31–33.

[159] See e.g. Hasanbeigi, Ali and Cecilia Springer. "How Clean is the U.S. Steel Industry? An International Benchmarking of Energy and CO2 Intensities." Global Efficiency Intelligence (November 2019), available from the Harvard's Belfer Center for Science and International Affairs at https://www.belfercenter.org/sites/default/files/files/publication/how-clean-is-the-us-steel-industry-nv.pdf, (concluding that "The U.S. steel industry's final energy and CO2 emissions intensities rank 4th lowest among the countries studied" and showing that the U.S. steel industry is the cleanest and most energy-efficient of the seven largest steel producing countries in the world).

SPECIFIC COMMENTS PERTAINING TO ELECTRIC ARC FURNACES AND ARKANSAS

XIV. EPA Has Identified No Legal Basis for Imposing Emission Unit Specific Limits on the U.S. Steel Facilities in Arkansas.

As discussed in Sections above EPA has no legal basis for regulating U. S. Steel facilities especially those in Arkansas. Notably, the *only* impact relied on for subjecting specifically Arkansas and Mississippi to the stringent non-EGU emission limits in the Proposed Rule is a single maintenance receptor in Brazoria County, Texas which EPA classifies as maintenance status, and projects to still be in maintenance status in 2026. See *Air Quality Modeling Technical Support Document* at D-1 & D-6. The fact that EPA has presented no analysis to support a conclusion that emission units at the U. S. Steel Arkansas facilities (which are located in Osceola, Arkansas, on the far opposite end of the state from TX, about 560 miles from Brazoria, Texas) contribute significantly to impacts at the Brazoria receptor is alone sufficient to require the exclusion of those facilities from the Proposed Rule. But for the sake of thoroughness, U. S. Steel requested the experienced air modeling team at Woodard & Curran to perform modeling to evaluate the significance of BRS's (and EV's, once it commences operation) contribution, if any, to the Brazoria receptor linked to Arkansas under EPA's modeling as demonstrated in the Woodard Report attached as Exhibit A.

First, Woodard & Curran evaluated the impact of BRS/EV on Brazoria based on the scaling factors used by EPA to evaluate the anticipated contributions of industry sectors in developing the Proposed Rule, including the emission units sought to be regulated under the Proposed Rule. More specifically, Woodard updated the emission inventory used by EPA to more accurately reflect the existing BRS facility and the EV facility under construction adjacent thereto,[160] then extrapolated BRS/EV's contribution to the Brazoria receptor using EPA's own state and receptor specific factors, as explained in Woodard and Curran's report. As noted in Table 3 to that report, EPA's calculation methodology would result in an estimate of less than 0.01 ppb contribution from BRS/EV to the Brazoria receptor. This is below the level of significance that EPA used to evaluate the significance of iron and steel facilities to individual receptors (0.01 ppb), and thus is insignificant even by EPA's own interpretation. Moreover, as explained in more detail in a subsequent comment, significance of impacts at a receptor should not be evaluated below 1 ppb, which is far higher than that calculated for BRS/EV. Finally, this calculation method is highly

[160] The BRS scrap to steel products facility in Osceola, Arkansas currently contains two Electric Arc Furnaces (EAFs), which are the only emission units at the facility with a potential to emit more than 100tpy of NOx. On January 31, 2022, AEEDEQ issued BRS a permit to construct and operate a new scrap to steel mill on land adjacent to the existing facility. BRS anticipates transferring the permit for the new mill to Exploratory Ventures (EV), a separate company, but which, like BRS, is owned by US Steel. Although this second facility is not integrated with and operates independently from the existing mill, BRS/EV understands that under existing EPA guidance, the two mills would be considered a single source under Title I of the Clean Air Act. Like the existing facility, the new facility will also have two EAFs, each with a potential to emit more than 100tpy of NOx. The new facility provided notice to AEEDEQ on May 12, 2022, of commencement of construction. Accordingly, the Woodard & Curran model conservatively accounts for all four EAFs in evaluating any potential impact on the Brazoria receptor.

conservative, since the extrapolation factors used in EPA's calculation do not account for where in a state a source is located, and BRS/EV is located in the far edge of the state, over 900 km from the Brazoria receptor.

Second, Woodard & Curran performed HYSPLIT modeling in coordination with AEEDEQ to evaluate impacts to the Brazoria monitor. EPA itself used HYSPLIT in this rulemaking to evaluate environmental justice impacts on a facility specific level for EGUs[161] (though EPA did not use it to evaluate EPA's authority to regulate individual facilities under the Proposed Rule in the first place). EPA has also previously approved the use of HYSPLIT to screen out areas in the similar context of regional haze.[162] HYSPLIT looks at the specific events during which ozone NAAQS exceedances are predicted and can generate a backtrajectory to identify what geographic regions airflows contributed to each specific predicted NAAQS exceedance. This provides more insight than the CAMx model into specific contributions on the specific days that EPA relies on to classify the Brazoria receptor as a maintenance receptor (especially the way that EPA ran CAMx, evaluating only aggregated statewide contributions in general without tagging industries or facilities like CAMx would have allowed EPA to do if EPA had attempted to do so).

HYSPLIT analysis also provides insight as to whether any potential linkages identified by CAMx are consistent and persistent.

EPA's CAMx modeling only looked at five to ten elevated ozone days and did not evaluate where the ozone and precursors arose that contributed to those days (i.e., although EPA looked generally to what states may have contributed, EPA did not evaluate or identify where in a given state contributions originated, since EPA chose to run CAMx without source tags).

To evaluate whether the U. S. Steel facilities in Arkansas could contribute to any of these ozone high events identified by EPA, Woodard & Curran used HYSPLIT to calculate seventy-two hour back-trajectories for the EPA's top-ten CAMx predicted maximum daily 8-hour 2026 ozone events for the ozone monitoring site located in Brazoria, TX. As noted in Woodard & Curran's attached report, the top three ozone days had contributing air parcels originating well outside of Arkansas, or only briefly passing through the very southern section of Arkansas, and in no event originated or passed through the northeastern portion of Arkansas where the U. S. Steel facilities are located. As a result, the U. S. Steel Arkansas facilities did not contribute to any of the events assessed by EPA, and thus cannot be said to significantly contribute to any maintenance issues evaluated by EPA at the Brazoria receptor.

Woodard & Curran is also in the process of performing confirmatory CAMx modeling to determine the source specific contributions to the Brazoria monitor which EPA neglected to evaluate. As EPA is aware, CAMx modeling can take significant time to complete, and although we are diligently pursuing this modeling, it is impossible to complete before the June 21 comment deadline. However, because the necessity of this modeling was created by EPA's failure to perform

[161] Policy Analysis TSD at 67.

[162] 87 Fed. Reg 7734 (Feb 10, 2022).

and/or disclose source-specific CAMx contribution modeling and unreasonably truncated public comment period, and because it bears directly on EPA's authority to regulate U. S. Steel at all under the Good Neighbor provision, EPA must consider this modeling whenever it is completed in determining applicability of any final rule to U.S. Steel facilities without running afoul of the Clean Air Act.[163]

XV. EPA Has Identified No Legal Basis for Regulating the Iron and Steel Industry in Any But Possibly One State, and Certainly Not in Arkansas

EPA has not demonstrated that the Iron and Steel industry in Arkansas (or virtually any state for that matter) is a "type of emissions activity within the State" that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State."

To begin, as previously noted, EPA's regulation of the iron and steel industry in Arkansas did not even comply with EPA's own oft-referenced "4-step interstate transport framework." Under that approach, EPA, after identifying nonattainment and maintenance receptors (step 1), and screening out any state not contributing at least 0.7ppb to any linked receptor (step 2), was then supposed to "(3) for states linked to downwind air quality problems, identify [] upwind emissions that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS; and (4) for states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in downwind areas, implement[] the necessary emissions reductions through enforceable measures."[164] But that is not what EPA did in the Proposed Rule. Rather than evaluate the upwind emissions actually contributing to each screened-in state's linked nonattainment or maintenance receptors, EPA instead just (1) identified industries *nationwide* that contributed at least 0.1pbb to at least one downwind receptor, or 0.01pbb to at least ten receptors[165]; and (2) automatically mandated limits directly on all such sources in each screened-in state, skipping any finding that these sources evaluated on a nationwide basis actually contributed to nonattainment or interfered in maintenance at the linked receptors for each particular state.[166]

Although it may be appropriate as a screening matter to initially identify industry sectors representing potentially significant NOx contributions on a national basis for further review, EPA cannot automatically skip to imposing regulations on all such industry sectors in all screened-in states without some showing that the industry sector at issue is significantly contributing to that particular state's linked nonattainment or maintenance receptors. This is because the Good Neighbor provision from which EPA derives any authority for such regulations only grants authority to prohibit emissions if a "type of emissions activity *within the State*" will "contribute

[163] In fact, using CAMx to simply repeat the modeling that USEPA performed takes longer than the comment deadline allows, particularly in light of how long EPA took to supply the underlying modeling data upon request.

[164] Proposed Rule at 20,041-42.

[165] EPA classified industries that satisfied both these criteria as "Tier 1" and those that satisfied only one as "Tier 2."

[166] Non-EGU Screening Assessment at 2-3, 22-23.

significantly to nonattainment in, or interfere with maintenance by, any other State."[167] Thus, it is arbitrary and capricious to regulate the steel industry nationally rather than regulating the appropriate sources (or at least appropriate industrial sectors) in each state actually contributing to the amount of emissions that need to be reduced from that state to fulfill its Good Neighbor obligations.

EPA also improperly conflated its own screening threshold for whether a state as a whole has a significant enough contribution to require reductions pursuant to the FIP, with the statutory requirement to evaluate significant contributions of a "source or type of emissions activity within the State." As the State of Arkansas rightly notes in it comments in response to EPA's proposed denial of Arkansas' proposed state implementation plan for the 2015 Ozone NAAQS as it relates to Good Neighbor obligations, EPA wholly failed "to show that specific sources in Arkansas are actually contributing significantly to the Harris County monitor or interfering with maintenance of the NAAQS by other receptors, thus EPA is effectively contending that a 1% linkage is the same as a significant contribution, which is not consistent with their guidance or Clean Air Act 110(a)(2)(D)(i). Determination of linkages and significant contributions occurs at separate steps in the four-step analysis. DEQ does not agree that a 1% linkage to an entire state is the same as a significant contribution from a source or emissions activity. The state's obligation is not to eliminate an arbitrary threshold (or to reduce emissions such that a neighboring state that may be its own primary contributor to nonattainment is not overburdened by their own obligations), but to determine if any emissions sources or emissions activity in the state are significantly contributing to a downwind nonattainment receptor or interfering with maintenance of the NAAQS by a downwind state and respond accordingly to mitigate significant contributions."[168]

If EPA had failed to evaluate the contributions of each screened-in industry in a state prior to subjecting it to regulation in that state, then EPA would have 'merely' failed to justify the regulation of such industry in each state. But EPA's failure to comply with statutory requirements is even more unreasonable, arbitrary, and unlawful here, because it appears that EPA *did* perform an evaluation of whether each industry contributed to nonattainment or maintenance issues at each states linked receptors, and then went on to attempt to regulate NOx emissions from each industry sector in each screened-in state despite specifically finding that many industries did not contribute to that state's linked receptors above the industry significance thresholds set by EPA.[169] For instance, EPA's own modeling found that the Iron and Steel industry only contributed to a nonattainment or maintenance receptor above EPA's own significance threshold (0.01ppb) in only one state and that state is not Arkansas, as show below[170]:

[167] 42 U.S. Code § 7410(a)(2)(D)(i)(I).

[168] See Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality, on EPA-R06-OAR-2021-0801-0001, at 22 (April 22, 2022).

[169] See Table A-3 to Non-EGU Screening Assessment.

[170] See Table A-3 to Non-EGU Screening Assessment.

Table A-3. Estimated Total, Maximum, and Average Contributions from Each Industry, and Number of Receptors with Contributions >= 0.01 ppb for 2023

Industry	# Facilities with Units > 100tpy	# Units > 100 tpy	Ozone Season Emissions	Total Contribution	Max Contribution	Average Contribution	# Receptors with Contributions >= 0.01 ppb	# States with Highest Contribution >= 0.01 ppb
Pipeline Transportation of Natural Gas	144	399	34,343	1.679	0.287	0.084	12	12
Cement and Concrete Product Manufacturing	61	84	36,244	1.871	0.231	0.094	19	13
Iron and Steel Mills and Ferroalloy Manufacturing	14	43	4,622	0.577	0.129	0.029	11	1
Basic Chemical Manufacturing	38	78	9,612	0.293	0.123	0.015	9	2
Glass and Glass Product Manufacturing	38	53	12,059	0.695	0.105	0.035	11	7
Petroleum and Coal Products Manufacturing	47	94	8,163	0.733	0.098	0.037	12	6
Metal Ore Mining	9	21	17,778	0.687	0.079	0.034	15	3
Lime and Gypsum Product Manufacturing	31	60	8,856	0.531	0.066	0.027	13	3
Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	16	27	3,680	0.162	0.044	0.008	3	1
Pulp, Paper, and Paperboard Mills	46	73	6,773	0.306	0.043	0.015	11	3
Oil and Gas Extraction	59	139	9,150	0.207	0.035	0.010	9	2
Nonmetallic Mineral Mining and Quarrying	8	18	3,808	0.167	0.035	0.008	4	1
Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing	10	16	1,779	0.152	0.027	0.008	7	2
Other Chemical Product and Preparation Manufacturing	7	8	683	0.074	0.024	0.004	3	1
Clay Product and Refractory Manufacturing	1	2	1,098	0.088	0.024	0.004	4	1
Chemical and Allied Products Merchant Wholesalers	1	4	573	0.032	0.019	0.002	2	1
Natural Gas Distribution	6	17	1,027	0.058	0.016	0.003	1	1
Water, Sewage and Other Systems	6	6	375	0.069	0.016	0.003	4	1
Pharmaceutical and Medicine Manufacturing	2	2	300	0.057	0.011	0.003	1	1

Although Table A-3 does not disclose the sole state with impacts from the iron and steel industry above EPA's significance thresholds for industry, the context suggests that state is almost certainly not Arkansas, as those are not among the states where the Non-EGU Screening Assessment identifies large potential reductions of NOx from the iron and steel industry.**171** Thus, EPA's own modeling appears to affirmatively demonstrate that Iron and Steel Industry is NOT a significant contributor to Arkansas' downwind linked maintenance receptor (Brazoria), and it would thus be arbitrary and unlawful for EPA to subject the steel industry in Arkansas and other such states to the Proposed Rule in the face of this specific finding. The same conclusions could be reached for the iron and steel industry in every other state without further analysis with the exception of the single state identified by EPA in the Proposed Rule.

It is particularly important for EPA to correct this approach given its determination that Arkansas may be overcontrolled under the Proposed Rule since their contributions to the Brazoria receptor are predicted to be erased based solely on imposition of controls on Tier 1 industry.[172]

EPA's request for comments on whether to only regulate Tier 1 industries in Arkansas and exempt Tier 2 industries also misses the statutory mark. EPA only has regulatory authority to prohibit amounts of emissions from a "source or other emissions activity" that will "contribute significantly to nonattainment in, or interfere with maintenance by, any other State." Thus, for Arkansas, EPA must consider whether an industry is actually a significant contributor to Arkansas' linked receptors, and it is arbitrary and unlawful for EPA to consider regulating an industry in Arkansas on some other basis (such as whether EPA considers an industry to be "Tier 1" or "Tier 2" as a nationwide matter). For instance, EPA's modeling suggests that for Arkansas, Pipeline Transportation of Natural Gas (a so called "Tier 1" industry) and Pulp, Paper, and Paperboard Mills (a so called "Tier 2" industry) are by far the industries where most of the emission reductions are expected to occur in Arkansas under the Proposed Rule, with potential reductions from Pulp, Paper, and Paperboard Mills dwarfing the amount of all other Tier 1 industries combined (other

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[171] See Non-EGU Screening Assessment at Figure 2 (identifying only IN, OH, and PA as having ozone season anticipated NOx reductions of more than 100 tons).

[172] Proposed Rule at 20,099.

than "Pipeline Transportation of Natural Gas").[173] Accordingly, EPA should avoid overcontrol and adhere to the statutory text by only regulating industries within a particular state which significantly contribute to that state's linked receptors, rather than by whether EPA happens to classify the industry as "Tier 1" or "Tier 2" on a nationwide basis.

XVI. There are Many Reasons to Conclude that the Proposed Rule Will Result in Impermissible Overcontrol, Specifically With Regard to Arkansas.

The Supreme Court has held that when drafting regulations to enforce the Good Neighbor provision, "EPA cannot require a state to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the 1% threshold the Agency has set" . Moreover, "if any upwind State concludes it has been forced to regulate emissions below the one percent threshold or beyond the point necessary to bring all down-wind States into attainment, that State may bring a particularized, as-applied challenge to the Transport Rule, along with any other as-applied challenges it may have." Notably, these pronouncements were made in the context of an EPA rule which placed statewide emission budgets on states (thus allowing states to challenge those emission budget) and did not impose facility/emission unit level command-and-control limits like the Proposed Rule. By the same rationale, because the Proposed Rule attempts to impose facility/emission unit level command-and-controls on the purported basis of such controls being necessary to fulfill Good Neighbor provisions, the Proposed Rule will be subject to facility level challenges from any facility on the basis that EPA's controls are more stringent than necessary to result in attainment of any downwind receptor to which the facility's state is linked. Accordingly, EPA's statement that any "claim that controls are not necessary to eliminate significant contribution would not suffice to justify an extension" is false; not only would such a claim justify an extension, but it should completely exempt such facilities from the Proposed Rule's limits altogether, since the Good Neighbor provision only grants authority to prohibit emissions "in amounts which will . . . contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard."

There are many reasons to believe that the Proposed Rule results in impermissible overcontrols, especially with regard to the Brazoria County, Texas receptor which is the only receptor Arkansas is linked to, and thus the only basis EPA has identified for imposing non-EGU limits in Arkansas.[174]

A. Brazoria Receptor Resolves Without Any Reductions from Arkansas and Mississippi.

To begin, the Brazoria County, TX receptor is a maintenance receptor, not a nonattainment receptor. To be sure, the courts have held that the Good Neighbor provision grants authority to prohibit not just amounts that will contribute significantly to nonattainment, but also those amount

[173] Non-EGU Screening Assessment at Table 4.

[174] While U.S. Steels comments in this section is limited to Arkansas, the same arguments could be made as it relates to the State of Mississippi, which is also linked solely to the receptor in Brazoria County, Texas.

that significantly "interfere with maintenance." However, "As the Supreme Court stated, under the 'interfere with maintenance' prong, EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.' If States have been forced to reduce emissions beyond that point, affected parties will have meritorious as-applied challenges."[175]

Brazoria is not just modeled to be a maintenance receptor; it is modeled to consistently improve and to be full attainment and non-maintenance before 2032, as shown below in EPA's own modeling values predicted for the Brazoria receptor in the absence of the Proposed Rule[176]:

Site ID	*ST*	*County*	*2016 Centered Avg*	*2016 Centered Max*	*2023 Avg*	*2023 Max*	*2026 Avg*	*2026 Max*	*2032 Avg*	*2032 Max*
480391004	TX	Brazoria	74.7	77	70.1	72.3	69.1	71.2	67.7	69.8

This is notably different from the scenario addressed by the D.C. Circuit in *Wisconsin v. EPA*, 938 F.3d 303, 326-27 (2019), when the court rejected a generalized argument that a state is necessarily overcontrolled if it is linked to only maintenance receptors yet subjected to the same control levels as states linked to nonattainment receptors. In the first place, that court rejected the claim before it because it was generalized, rather than alleging an as-applied challenge to a specific instance of overcontrol, and because the rule at issue in that case was not expected to fully satisfy upwind States' Good Neighbor responsibilities.[177] But neither of those apply here, to this particularized instance of overcontrol at the Brazoria receptor, in the context of a Proposed Rule designed to fully satisfy upwind States' Good Neighbor responsibilities. Additionally, the court in *Wisconsin* noted that ''the possibility of failing to maintain the NAAQS in the future, even in the face of current attainment of the NAAQS, is exactly what the maintenance prong of the Good Neighbor provision is designed to guard against.''[178] But here, by contrast, the Brazoria County, Texas receptor is not modeled to continue to be a maintenance monitor in danger of slipping to nonattainment, instead it is modeled to trend in the opposite direction, going out of maintenance into full attainment without any application of the Proposed Rule.[179] For this specific receptor, it would thus result in overcontrol to require the draconian NOx reductions required in the Proposed Rule for the states linked only to this receptor.

[175] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 137 (D.C. Cir. 2015) (quoting *EPA v. EME Homer City Generation, L.P.*, 572 U.S. at 515 n.18).

[176] Air Quality Modeling Technical Support Document at Appendix B, B-3.

[177] *Wisconsin v. EPA*, 938 F.3d 303, 327 (2019).

[178] *Wisconsin v. EPA*, 938 F.3d 303, 326 (2019) (quoting 81 Fed. Reg. at 74,531).

[179] Note also that this conclusion is not affected by potential future industrial growth in upwind states, both because EPA already accounted for anticipated future emission inventory changes, and because any new major sources must undergo PSD evaluations to ensure they do not adversely affect any NAAQS compliance.

B. EPA's Modeling Significantly Underestimates Reductions Associated with the Proposed Rule, Instead Demonstrating that Downwind Linked Receptors are Resolved by Significantly Less Stringent Non-EGU Controls than the Proposed Rule

As explained in more detail below, the modeling used to conclude that the Proposed Rule does not result in overcontrol, specifically at the Brazoria receptor, is based on estimated reductions from each covered non-EGU sector in each state which are far smaller than the emission reductions that would be imposed by the limits in the Proposed Rule. Because EPA's screening assessment shows that sources in Arkansas can reduce emissions sufficiently to bring the Brazoria receptor into full attainment without consideration of numerous excluded facilities (including U. S. Steel's BRS and EV facilities) and without installing SCR on any EAF or other emission units at iron and steel facilities in Arkansas, EPA's decision to nonetheless require stricter emission controls than modeled, on more facilities than modeled, means that the Proposed Rule's emissions limits must result in overcontrol. And because there is substantial overcontrol in Arkansas, all the Proposed Rule's emission limits on non-EGUs (including U. S. Steel's BRS and EV facilities) are arbitrary and capricious because there is no way to determine which limits are necessary to avoid interference with maintenance at the Brazoria receptor.

More specifically, the Proposed Rule relies on the non-EGU Screening Assessment as the basis for the Proposed Rule's evaluation of reductions associated with the Proposed Rule.[180] But EPA drafted this screening assessment before it had performed the air quality modeling underlying the Proposed Rule, and as a result, used a different emission inventory than the emission inventory prepared for the rest of the Proposed Rule.[181] The docket includes a technical support document dedicated to explaining that the non-EGU Screening Assessment was not even designed to capture the facilities that would actually be subject to the Proposed Rule.[182] In EPA's words "Using the emissions thresholds and other factors laid out in the Screening Assessment, EPA generated a preliminary list of non-EGU facilities and emissions units to inform the development of the Proposed Rule. The list of non-EGU facilities and emissions units generated during the Screening Assessment did not constitute a determination by EPA that the identified non-EGU facilities and emissions units are covered by the Proposed Rule. The information on facilities and emissions units provided in the Screening Assessment is likely not a complete listing of the non-EGU

[180] Proposed Rule at 20,056 ("Section III of the Non-EGU Screening Assessment memorandum in the docket for this rulemaking describes EPA's approach to evaluating impacts on downwind air quality, considering estimated total, maximum, and average contributions from each industry and the total number of receptors with contributions from each industry.").

[181] Non-EGU Screening Assessment at 2 n.2 ("We used the [Revised CSAPR Update] air quality modeling for this screening assessment because the air quality modeling for the Proposed Rule was not completed in time to support this assessment.").

[182] See "Technical Memorandum Describing Relationship between Proposed Applicability Criteria for Non-EGU Emissions Units Subject to the Proposed Rule and EPA's 'Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026'" (Memo re Relationship of Proposed Rule to Screening Assessment).

facilities and emissions units potentially covered by the Proposed Rule." In other words, when EPA performed its modeling to evaluate potential emission reductions, EPA did not include the facilities that would be subject to the Proposed Rule, nor the limits that would actually apply to the emission units at those sources.

As a result, this "preliminary list of non-EGUs" notably omits many facilities that would be impacted by the Proposed Rule, and significantly underestimates the emission reductions from some it does include. For instance, in Arkansas, the Non-EGU Screening Assessment included a single emission unit at Nucor-Yamato as the only unit evaluated from the Iron and Steel industry, resulting in reductions of only 6 ozone season tons (15tpy) estimated from the entire iron and steel industry in Arkansas.[183] This absurdly underestimates the reductions that the Proposed Rule would require in Arkansas alone for multiple reasons:

- Even at the one steel mill in Arkansas included in the non-EGU Screening Assessment, the Nucor unit is listed as having annual NOx emissions of only 19tpy.[184] But given that the screening assessment claims to only evaluate emission units with a potential to emit over 100tpy of NOx, this is an error (whether a typo, a selection of the wrong unit at the facility or otherwise). Either way, the Proposed Rule would decrease the permitted lb/ton NOx rate for this facility's (Nucor) EAFs from the current permit limit of 0.38 lb/ton[185] to the Proposed Rule limit of 0.15 lb/ton (i.e., a 0.23 lb/ton reduction). At an average steel production rate of 500 tons per hour[186] times 3,672 hours per ozone season,[187] that represents a potential reduction of up to 422,280 lb (i.e. 211.14 ozone season tons) from this facility's EAFs alone;
- Furthermore, the screening assessment completely omits the existing U. S. Steel's BRS facility (despite the fact that EPA was surely aware of it since EPA used the facility permit as one of the bases for the Annealing Furnace lb/mmBtu limit in the Proposed Rule).[188] At BRS alone, the Proposed Rule would decrease the permitted lb/ton NOx rate for each of the facility's two EAFs by up to 50%, by reducing the current permit

[183] See excel file titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List," which states that "This file provides the list of facilities in 23 states that EPA evaluated in the Technical Memorandum: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026."; see also non-EGU Screening Assessment at Figure 2 (estimating a total of 1,654 ozone season tons NOx reduction from Arkansas, only 6 of which come from the Iron and Steel industry in Arkansas for) and compare also Proposed Rule at 20,090 (carrying through the non-EGU Screening Assessment without further analysis).

[184] See excel file titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List".

[185] See Nucor-Yamato Steel Company permit no. 0083-AOP-R17, available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0883-AOP-R17.pdf

[186] See Nucor-Yamato Steel Company permit no. 0083-AOP-R17 at 3.

[187] 153 days in Ozone Season of May-September times 24 hours per day.

[188] Proposed Rule at 20,145.

limit of 0.3 lb/ton[189] to the Proposed Rule limit of 0.15 lb/ton. At a presumed capacity of 250 tons/hr each,[190] times 3,672 hours per ozone season,[191] that represents a reduction of up to 275,400 lb (i.e. 137.7 ozone season tons) from the facility's two existing EAFs alone;[192]

- U. S. Steel's BRS and Nucor-Yamato are just two of the four Iron and Steel facilities in Arkansas identified by EPA in the modeling used to develop a base case for the Proposed Rule.[193] Accordingly, the screening assessment wholly ignored the reductions the Proposed Rule would force at those other facilities as well.

Notably, this underestimation issue applies beyond Arkansas as well; in fact only one U.S. Steel facility nationwide was accounted for in the screening assessment at all.[194]

By contrast, EPA did include many sources that were not included in the non-EGU Screening Assessment (including U. S. Steel's BRS facility) when later modeling the base case of emissions for the Proposed Rule.[195] *The net result is that EPA accounted for NOx emission from the U. S. Steel BRS* facility when it collectively estimated the impacts of Arkansas as a whole on the Brazoria County, Texas receptor, but not when calculating the reductions expected from non-EGUs from Arkansas as a result of the Proposed Rule. The only conclusion that can be reached is that EPA significantly underestimates the reductions that the Proposed Rule would require.[196] And the fact that this underinclusive modeling was used as the basis for concluding that the Proposed Rule does not result in overcontrol renders EPA's conclusions regarding overcontrol both in general, and especially with respect to Arkansas, arbitrary and capricious.

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[189] See Big River Steel Permit No. 2305-AOP-R7, available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/2305-AOP-R7.pdf

[190] Big River Steel Permit No. 2305-AOP-R7, at 68.

[191] 153 days in Ozone Season of May-September times 24 hours per day.

[192] As noted, other units, including most notably the LMF, vents to the same canopy as the EAF, and U. S. Steel's BRS facility air permit provides a combined lb/hr rate for each EAF/LMF combination. Accordingly, the amount of emission reductions expected by the rule will in some part depend on whether facilities are required to show decreases from an EAF alone (which is not technically feasible given that any CEMS in the exhaust will be measuring combined emissions of the EAF and LMF), or instead allows compliance to be demonstrated based on the sum of the proposed limits for EAFs and LMFs or some other mechanism. But in any case, the emission reductions would be far above those estimated in the non-EGU Screening Assessment.

[193] See excel file in regulatory docket titled "Summaries of point source emissions used in aqm _att 4 - ptnonipm facility 16 17 18 19 23 26 32 comp 29sep2021".

[194] See excel file in regulatory docket titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List," (identifying only the Clairton Works facility in Allegheny County PA).

[195] See excel file in regulatory docket titled "Summaries of point source emissions used in aqm _att 4 - ptnonipm facility 16 17 18 19 23 26 32 comp 29sep2021" (listing NOx emissions for BRS facility for 2017, 2018, and 2019).

[196] This assumes for the sake of argument that the reductions required by the Proposed Rule are even possible, as addressed herein under the section regarding feasibility.

Rather than take the next step and attempt to estimate what reductions would be associated with the Proposed Rule's command-and-control limits for the iron and steel industry, EPA instead just used the statewide emission reductions from the severely underinclusive non-EGU Screening Assessment as the basis for EPA's estimate of state-by-state expected NOx reductions, which then formed the basis of EPA's conclusion that the rule does not result in overcontrol.[197] Put another way, it appears that EPA's own modeling concluded that even the severely underestimated non-EGU emission reductions would be sufficient to pull the Brazoria County, Texas receptor into attainment.[198] Accordingly, if EPA nonetheless requires the emission limits in the Proposed Rule, which will result in reduction in NOx emissions far above what EPA modeled to result in attainment for the Brazoria receptor (only 6 ozone season tons), EPA is overcontrolling in violation of the Supreme Court's mandate that "under the 'interfere with maintenance' prong, EPA may only limit emissions 'by just enough to permit an already-attaining State to maintain satisfactory air quality.'"[199]

C. The Proposed Rule Fails to Account for Enforceable Closures of EGUs Which Will Result in Overcontrol if Non-EGUs in Arkansas to Subjected to Regulation

EPA fails to account for enforceable closures of multiple EGU units in Arkansas, which, as explained below, will eliminate more NOx contribution from the State of Arkansas than the entirety of all reductions the Proposed Rule seeks from Arkansas. Accordingly, requiring the Proposed Rule's limits for non-EGUs on top of these closures will result in overcontrol.

The following three Entergy power plants are subject to closure pursuant to settlement agreements soon after the 2015 Ozone NAAQS serious attainment deadline of August 2027, and years before the final attainment date under the 2015 Ozone NAAQS of August 2033 for severe nonattainment[200]:

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[197] Proposed Rule at 20,098 ("using the Ozone AQAT, the EPA first evaluated whether reductions resulting from the selected control stringencies for EGUs in 2023 and 2026 combined with the emissions reductions selected for non-EGUs in 2026 can be anticipated to resolve any downwind nonattainment or maintenance problems (see the Ozone Policy Analysis Proposed Rule TSD for details on the construction and application of AQAT)."); see also Policy Analysis TSD at 34, noting that for non-EGUs, *estimated reductions at receptors was based on the non-EGU assessment* ("In the ozone AQAT, EPA links state-by-state NOX emission reductions (derived from the photochemical model, the non-EGU assessment and/or the IPM EGU modeling combined with the EGU engineering assessment) with 2026 CAMx modeled ozone contributions in order to predict ozone concentrations at different levels of emission levels at monitoring sites.") (emphasis added); *see also* Proposed Rule at 20090 (carrying through the non-EGU Screening Assessment estimates of state-by-state potential NOx reductions without further analysis);

[198] Non-EGU Screening Assessment at Table 3 (concluding that Tier 1 industry reductions estimated from the Screening Assessment alone would result in attainment for Brazoria receptor); see also 20,098 (parroting result of underinclusive Screening Assessment with regard to the Brazoria Receptor).

[199] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 137 (D.C. Cir. 2015) (quoting *EPA v. EME Homer City Generation, L.P.*, 572 U.S. at 515 n.18).

[200] https://www.arkansasonline.com/news/2021/mar/12/in-settlement-power-plants-to-shut-by-30/

- 50-year-old natural gas units at Lake Catherine by the end 2027 (permitted for 53,000tpy of NOx,[201] actual 2019 ozone season emissions of 173 tons[202])
- Coal-fired White Bluff Power Plant by the end of 2028 (permitted for 53,000tpy of NOx,[203] actual 2019 ozone season emissions of 2,908 tons[204])
- Coal-fired Independence Power Plant by the end of 2030 (permitted for 53,000tpy of NOx,**205** actual 2019 ozone season emissions of 2,845 tons[206]).

Notably, in the Proposed Rule, EPA found that the Proposed Rule constitutes a full satisfaction of Good Neighbor obligations based on only 1,654 *total statewide* ozone season tons reduction from non-EGUs in Arkansas.[207] Accordingly, the closure of White Bluff alone in 2028 or earlier will reduce statewide emissions by almost double the amount that EPA considers sufficient to resolve Arkansas' Good Neighbor obligations, making any control of non-EGUs at that point an impermissible overcontrol unnecessary to satisfy Arkansas' Good Neighbor obligations.

Furthermore, these facilities are much closer to the Brazoria County, Texas and are more likely to interfere with that receptor than are the U. S. Steel BRS and EV facilities.

Although these enforceable closures are not scheduled to occur prior to EPA's proposed 2026 deadline for non-EGUs to comply with the Proposed Rule, that is not a reasonable excuse for failing to take them into account, at least with respect to Arkansas, for at least two reasons.

1. As further discussed herein in the comment section on timing, EPA's selection of a compliance deadline of 2026 is based on deadlines applicable to downwind nonattainment regions, and thus it is not necessary or reasonable to require the same deadline where only attaining maintenance receptors are affected, as is the case with Arkansas which is linked solely to the Brazoria County, Texas receptor, which as previously discussed above, is predicted to be in attainment (but still maintenance) by

[201] Permit available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/1717-AOP-R9.pdf

[202] See EPA's power plant dataviewer (most recent data from 2019), available at https://www.epa.gov/airmarkets/power-plant-data-viewer

[203] Permit available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0263-AOP-R16.pdf

[204] See EPA's power plant dataviewer (most recent data from 2019), available at https://www.epa.gov/airmarkets/power-plant-data-viewer

[205] Permit available at https://www.adeq.state.ar.us/downloads/WebDatabases/PermitsOnline/Air/0449-AOP-R17.pdf

[206] See EPA's power plant dataviewer (most recent data from 2019), available at https://www.epa.gov/airmarkets/power-plant-data-viewer

[207] Proposed Rule at 20,090.

2023, to improve even further by 2026, and be full attainment (i.e., no longer maintenance) by or before 2032.[208]

2. The Proposed Rule suggests exempting EGUs from the backstop daily rates otherwise applicable to EGUs in 2026, so long as the EGUs close by 2028,[209] effectively treating 2028 as the effective compliance deadline where EGU closures are concerned.[210] EPA raises many good reasons for considering 2028 given the many changes relevant to air quality that will occur in 2028, including EGU closures in response to new Clean Water Act effluent guidelines and the coal combustion residuals rule under the Resource Conservation and Recovery Act, and the fact that "2028 also represents the end of the second planning period under the Regional Haze program, and thus is a significant year in states' planning of strategies to make reasonable progress towards natural visibility at Class I areas." [211] Notably, EPA proposes to allow EGUs to postpone limits until 2028 even in states actually tied to a nonattainment downwind receptor (unlike Arkansas), which are under an obligation to resolve their linkage by the time of downwind states' attainment deadline pursuant to *Wisconsin v. EPA*.[212] Given all of these emission reductions anticipated in 2028, and EPA's consideration of these factors in postponing compliance deadlines from 2026 to 2028 in the context of EGU closures, EPA should also take into account closures anticipated by 2028 (including the White Bluff plant in Arkansas) in evaluating the need to regulate non-EGUs.

Given the fact that EPA already identified changes in 2028 as reasonable to consider in setting compliance obligations (including even for States that are predicted to have impacts on nonattainment areas beyond 2026), the fact that Arkansas is not linked to any nonattainment receptor that requires an obligation to resolve the linkage by the time of the downwind state's attainment deadline, and the fact that the closure of White Bluff Power Plant in 2028 would alone eliminate more emissions than EPA models are needed from all non-EGUs combined in Arkansas to ensure attainment at the Brazoria receptor, it would constitute impermissible overcontrol of the Brazoria receptor to subject non-EGUs in Arkansas to the Proposed Rule.

XVII. EPA Fails to Demonstrate that the Proposed Limits and the Theoretical Controls They are Based on Are Technically Feasible.

[208] Air Quality Modeling Technical Support Document at Appendix B, B-3.

[209] EPA's flexibility around the 2026 deadline for EGUs also extends to facilities which will not shut down in 2028, as EPA proposes to not require unit specific backstop emission rates until 2027 for facilities that do not already have SCR installed. See Proposed Rule at 20,111-12.

[210] Proposed Rule at 20,122.

[211] Proposed Rule at 20,122.

[212] Notably even EPA relies on not being required to achieve the impossible. See Proposed Rule at 20062 ("implementing good neighbor obligations beyond the dates established for attainment may be justified on a proper showing of impossibility or necessity.").

As explained above in Section II., when applying RACT, which Congress has made the express determination is the appropriate level of control when addressing Ozone NAAQS nonattainment, and which EPA claims it meant to follow in developing the Proposed Rule, EPA must demonstrate that the proposed limits are both technically and economically feasible on a facility and unit specific basis. And even stricter standards like BACT still require an analysis of technical and economic feasibility. And in any case, EPA has an independent "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[213] and EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[214] And thus EPA's assumptions regarding feasibility in the Proposed Rule must be adequately justified.

The comments in this section are specifically tailored to EAFs because those are the only furnaces used at U. S. Steel's Arkansas facilities with a potential to emit more than 100tpy of NOx, and thus are the only units the Proposed Rule would apply to, since the Proposed Rule only aggregates emissions for the purposes of applicability in the case of a BOF Shop (which would not apply to an EAF given that EAFs and BOFs are different processes, as noted throughout these comments, and throughout the Proposed Rule and its supporting materials). If EPA changes course in the final rule and expands the applicability of the limits in the Proposed Rule, we reserve our right to challenge such applicability and/or provide additional comments regarding any other such units EPA may extend applicability to. In any case, many of the following comments also apply to the other furnace types covered by the rule since EPA has not conducted an adequate feasibility analysis for any iron and steel industry emission unit sought to be regulated under the Proposed Rule.

A. The Controls EPA Bases the Proposed Iron and Steel Industry Emission Limits on Have Never Been Demonstrated in Practice, and EPA's Analysis of Feasibility is Provides Zero Basis to Conclude that They Could be Technically Feasible.

EPA expressly acknowledges that the emission limits for the iron and steel industry, including but not limited to furnaces, are below anything that has ever been achieved in the industry, expressly noting that EPA reviewed permits to find the best performing sources, then requires reductions below what the most stringent existing permits require. The only basis EPA provides for assuming that such reductions are possible is that EPA "[a]ssumes 25% reduction by SCR" for steel mill EAFs.[215] But none of EPA's underlying documentation or data ever evaluate the technical feasibility of retrofitting SCR on steel mill EAFs, or the level of emission reductions available from such a retrofit on an EAF. Simply put, not everything is equivalent to a coal-fired powerplant even though EPA's technical support document incorrectly makes that assumption.

With regard to the technical feasibility of installing an SCR on an EAF, the Proposed Rule does not point to any steel mills that have successfully installed SCRs on an EAF, nor is U.S. Steel

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[213] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

[214] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

[215] Proposed Rule at 20,145.

aware of any EAF facility to have successfully done so in the world (and there are good reasons for this, as explained in the following subsection).[216] The BRS facility underwent PSD review in 2013 and the new EV facility underwent PSD review in 2021. BACT analyses were submitted with both applications. EPA provided comments on the draft BRS permit in 2013 but did not comment on the 2021 application. In both instances, the application of SCR was eliminated from consideration because the technology is not technically feasible. Other PSD permits issued to EAFs in recent years, all subject to review and comment by EPA, reach similar conclusions. Furthermore, EPA has specifically concluded in the past that "the use of electricity to melt steel scrap in the EAF transfers NOx generation from the steel mill to a utility power plant. *There is no information that NOx emissions controls have been installed on EAF's or that suitable controls are available*."[217]

EPA is required to "provide a more detailed justification than what would suffice for a new policy created on a blank slate" when it promulgates a "new policy [which] rests upon factual findings that contradict those which underlay its prior policy" and an "Agency may not . . . depart from a prior policy sub silentio."[218] There can be little question that the Proposal both departs from prior positions without rationale, and contradicts factual findings underlying its prior policies:

1. EPA abandons its own edict that each unit must be assessed "on an individual basis to determine whether SCR is a feasible control technology"[219]—EPA has not provided any feasibility analysis for steel mill EAFs generally, let alone for each EAF "based on its site-specific characteristics." In fact, the very document which the Proposed Rule cites as the basis for concluding that SCR will reduce emissions from EAFs[220] expressly states that "This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however,

[216] In connection with the preparation of these comments, U.S. Steel consulted extensively with SMS Group, which is one of the world's leading suppliers of technology in the iron and steel industry and is the main technology provider for EAFs and other steelmaking equipment at U.S. Steel's BRS and EV facilities. According to the SMS Group, it is aware of no facilities in the world where SCR technology has been installed to control NOx emissions from steel mill EAFs. Black and Veatch's discussion with SCR vendors confirms this conclusion.

[217] Alternative Control Techniques Document – NOx Emissions From Iron and Steel Mills (EPA-453/R-94-065) (September 1994), at pg. 5-23; See also Point and NonPoint NOx Menu of Control Measures, at 15-16 (2012) (only identifying post combustion NOx controls as feasible for certain furnace types in the iron and steel industry, but not for electric arc furnaces). Note that there are natural gas burners used to assist the process, but these are responsible for less than 30% of the NOx emissions associated with an EAF, with the bulk of emissions being associated with the electric arc process, which is not a combustion process. Furthermore, the burners used are already low-NOx such that further emission reductions from burner replacements cannot be assumed to be feasible.

[218] *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515-16, 129 S. Ct. 1800, 1811 (2009).

[219] EPA Comments to Cost Estimate Manual, SCR Chapter, pg. 9, 13-14.

[220] Proposed Rule at 20,146 citing the "non-EGU screening assessment" as the basis for estimated "reductions of 20 to 50 percent" for iron and steel mills.

CoST was designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses."[221]

2. EPA has not provided any justification for its newfound belief that SCR is a feasible control for steel mill EAFs. Specifically, the Proposed Rule does not detail what if any relevant change to EAF or SCR technology has occurred since 1994 which would make SCR technically feasible NOx control for an EAF. [222]

3. EPA has historically refused to adopt unproven applications of technologies even in other programs where EPA has broad authority to require NOx reductions.[223]

Despite these past practices and findings, EPA nonetheless skips any analysis of unit specific feasibility, or even technical feasibility for EAFs in general, while nonetheless imposing limits that expressly presuppose such feasibility.

With regard to emission reductions expected, the Proposal purports to base its assumption of "reductions of 20 to 50 percent" for iron and steel mills "on the selection of SCR, SNCR, and burner replacement in the non-EGU screening assessment."[224] But the non-EGU screening assessment never assessed emission reductions associated with installation of an SCR at a single EAF.[225] And for newer facilities like U.S. Steel's BRS or EV facilities, which have undergone BACT review in recent years, low NOx burner technology is already in place. EPA does not explain or acknowledge this disconnect and provides no other rationale for why an SCR (or other technologies) can be assumed to reduce NOx emissions on an EAF by more than 20%-50%. Because the Proposed Rule's assertion that steel mill EAFs can achieve required emission limits by installing SCRs or other technologies is unsupported by the screening assessment on which EPA purports to base its assumptions, the Proposed Rule is arbitrary and capricious since "the agency has failed to 'examine the relevant data' or failed to 'articulate a rational explanation for its actions.'"[226] Nor does EPA attempt any facility or emission unit level analysis of whether the

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[221] Non-EGU Screening Assessment at 7.

[222] Alternative Control Techniques Document – NOx Emissions From Iron and Steel Mills (EPA-453/R-94-065) (September 1994), at pg. 5-23.

[223] E.g., "Acid Rain Program; Nitrogen Oxides Emission Reduction Program," 61 Fed. Reg. 67,112, 67,151 (December 19, 1996) (In the context of setting NOx emissions under the Title IV Acid Rain program, finding "The AEP demonstration of retrofitting a two-stage OFA system to a wet bottom boiler has not proved to be successful as yet. Thus, EPA does not find this technology to be the best system of continuous emission reduction for wet bottom boilers and is not using the technology to establish a NOx emission limit for wet bottom boilers in this rulemaking.")

[224] Proposed Rule at 20146; Non-EGU Sectors TSD at 43.

[225] Non-EGU Screening Assessment at Table 6 (only identifying SCR as a control technology evaluated for BOF, Blast Furnace, and Sintering processes in the Iron and Steel Industry). In fact, Table 6 reveals that the non-EGU Screening Assessment did not include analysis of <u>any controls</u> at any EAF at all (unless the EAF was for some reason classified as "Industrial Process – General" of "Industrial Process – Other Not Classified," neither of which was evaluated for SCR in any case).

[226] *Genuine Parts Co. v. EPA*, 890 F.3d 304, 311-12, 435 U.S. App. D.C. 338 (D.C. Cir. 2018) (quoting *Carus Chem. Co. v. EPA*, 395 F.3d 434, 441, 364 U.S. App. D.C. 339 (D.C. Cir. 2005)).

technology required would actually reduce NOx emissions. This is in notable contrast to prior rulemakings, where EPA at least attempted to consider levels of emission reductions that might be achieved at individual non-EGU facilities in light of the feasibility of control installation if they were subjected to Good Neighbor regulations.[227] EPA's failure to conduct emission unit-specific assessments of technically feasible emission reductions for the non-EGUs EPA subjects to the emission limits under Proposed Rule is particularly arbitrary in light of EPA's treatment of California's EGUs, which EPA proposes to exempt from the Proposed Rule based on a facility or emission unit specific analysis that significant additional potential emission reductions from the relevant EGU would not be technically feasible,[228] an analysis EPA refused to conduct for any other facility nationwide.

Finally, it is not even clear that EPA based its assumption regarding EAF lb/ton limits currently achieved in practice on a review of solely facilities that have EAFs. For most of the other iron and steel furnace types, EPA identifies which facility permit or state RACT limit EPA reviewed and used as a basis for identifying a lb/ton efficiency limit currently achieved for that furnace type, which EPA assumes could be lower by use of SCR.[229] But for EAFs, EPA does not identify any facility permit by name, instead the Proposed Rule vaguely states that EPA found "Example permit limits at around 0.2 lb/ton" [230] The Non EGU Sectors TSD further states that, for EAFs, "EPA considered a range of baseline emission data and permit limits from mini mills, integrated iron and steel facilities, and ferroalloy facilities ranging from 0.20 lb/ton to 0.35 lb/ton."**231** Because integrated iron and steel facilities generally use Blast Furnaces and BOFs and not EAFs, and ferroalloy facilities do not use EAFs[232] this suggests that EPA looked at non-EAF units as a basis for setting the NOx emission limits for EAFs in the Proposed Rule.[233] To the extent that EAFs at a given facility have an emission rate higher than 0.2 lb/ton identified by EPA, then the SCR control technology proposed by EPA, even if technically feasible to install (which it is not), would have to be shown to be capable of reducing emissions by greater than 25% to justify EPA's assumption that the proposed limits are possible to achieve. For instance, at a facility

[227] See non-EGU emissions reduction assessment prepared for the Revised Cross State Air Pollution Rule Update, available at www.regulations.gov/document/EPA-HQ-OAR2020-0272-0014

[228] Proposed Rule at 20,088.

[229] See Proposed Rule at 20,145.

[230] See Proposed Rule at 20,145.

[231] Non-EGU Sectors TSD at 43.

[232] See Proposed Rule at 20181 (defining an "Electric Arc Furnace" as only those furnaces "equipped with electrodes used to produce carbon steels and alloy steels primarily by recycling ferrous scrap.").

[233] To the extent EPA based the 0.2 lb/ton limit off of the Title V Operating Permit issued to Timken Faircrest in North Canton, OH, there is no such enforceable limit in this permit. The permit establishes a monthly NOx emission limit of 10.833 tons/month averaged over a 12-month basis. See http://wwwapp.epa.ohio.gov/dapc/permits_issued/1448372.pdf . Such a limit is not the same as a 0.2 lb/ton limit averaged over a 3-hour or even 30-day period, particularly since the compliance demonstration is based upon a stack test performed in 2006 (as opposed to the Proposed Rule, which would require compliance demonstrations based upon CEMs).

achieving 0.3 lb/ton with low NOx burners, an SCR would have to be capable of reducing NOx by at least another 50% for the 0.15 lb/ton limit to be possible to achieve.

In addition, while it is true that EPA was able to avoid considerations of unit specific feasibility in prior Good Neighbor rulemakings and simply focus on "fleet average" characteristics, that is only accurate because all such prior rulemakings were based on emission trading schemes with statewide budgets, rather than imposing emission limits on a unit specific basis as it now proposes to do for the first time ever under the Proposed Rule. Even EPA's prior rulemakings acknowledged that that "unit-specific short-term emission rates pose significant implementation and rulemaking challenges," and if EPA were "to choose to implement a unit-specific emissions rate regime for implementation, the compliance flexibility afforded by emissions trading would not be available and it would not be possible to rely on fleet average information to the same extent . . . ."[234] . Thus, EPA cannot evade unit specific feasibility analysis by merely pointing to past rulemaking while ignoring this fundamental difference between an emissions trading program and command-and-control emission limits it seeks to impose on the iron and steel industry. This is especially important where proposed limits begin reaching or exceeding limits of technological feasibility. If EPA wishes to impose emissions limits on a unit specific basis under the Good Neighbor provision of the Clean Air Act, at a minimum, EPA must address the technical feasibility of emission limits on an emission unit basis.[235]

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[234] *Id.*

[235] The comments in this section are specifically tailored to EAFs because those are the only emission units used at U. S. Steel's Arkansas facility (BRS and the EV facilities) with a potential to emit more than 100tpy of NOx. However, these same comments also apply to the other furnace types covered by the Proposed Rule since EPA has not conducted any adequate feasibility analysis for any such furnaces, only identifying a coal-fired annealing furnace as the only furnace type at which an SCR has been demonstrated, and not attempting any facility level feasibility analysis for any furnace type or facility subject to the Proposed Rule. And EAFs are not at all like annealing furnaces. Furthermore, other furnace types have their own unique considerations that would make SCR, SNCR or other controls like low NOx burners not technically feasible; for example, NOx emissions from vacuum degassers are caused only by the control device itself (the flare), and involve very low total emissions of NOx (permitted at 2tpy at U. S. Steel Arkansas facilities), and SCR (or SNCR or any other post-combustion controls) has not been demonstrated to be technically possible let alone feasible or cost effective on either a flare or on such low emission levels. Additionally, the tunnel furnace at the U. S. Steel BRS facility operates at a far higher temperature than SCR can feasibly operate at (over 1000 degrees) (and under what an SNCR can accommodate), and iron oxide scale generated from the slabs rolling over the rollers would bombard any catalyst installed, plugging it and reducing its efficiency and life, and furthermore each time that the door opens to accept a new shuttle there is a sudden increase in air input, causing discontinuity to fluegas airflow which can in turn lead to additional ammonia slip, and even if possible to retrofit, any retrofit would not be cost justified for a source that is under 100tpy of potential NOx emissions, and is already equipped with low-NOx burners such that further reductions based on burner replacement cannot be assumed. Furthermore, although some annealing furnaces may be larger stacked units, many annealing furnaces such as those at the U. S. Steel Arkansas facilities are small (under 6 tpy potential to emit) and only intermittently operated batch processes that are not even stacked, and thus are not amenable to control by CEMS, SCR or other post-combustion control. Also, to the extent SCR is not technically feasible to install in the vents from the EAF, they will likewise necessarily not be feasible to install for any of the small supporting units in the meltshop (including ladle/tundish preheaters, and ladle metallurgy furnaces), since those units do not have independent stacks and instead vent to the same canopy collecting emissions from the EAF. To the extent EPA makes any applicability

B. *There are Many Reasons to Conclude that SCR is Not Technically Feasible for EAFs, and/or Would Not Result in the Emission Reductions Assumed by EPA.*

There are good reasons why no EAF has ever demonstrated SCR controls in practice – there are many technical issues which could either render installation infeasible or would prevent the SCR from generating the emission reductions it may have in other contexts. This section summarizes many such issues and is informed by BRS' discussions with one of the largest worldwide designers and providers of EAF technology, the SMS Group, and a principal designer of EAF technology utilized at the BRS and EV facilities ("BRS/EV facility"). Neither the SMS Group nor the SCR vendors consulted by Black & Veatch are aware of any EAF steelmaking facility in commercial operation that has successfully installed SCR to control NOx. The attached memorandum from Black & Veatch, an engineering firm with actual experience designing and installing SCR systems at EGUs, also includes more detailed and technical critiques of the technical and economic feasibility of installing SCR at the BRS/EV facility and we hereby incorporate that memorandum by reference.

EAFs are a fundamentally different process than the EGUs at which SCR has been demonstrated. For one, unlike the relative continuous process associated with EGUs, an EAF is a batch process, with emission spikes when the furnace is charged with scrap and the electrodes bore-in initiating the arc (e,g, tapping), as well as emission profile and temperature shifting throughout the melt cycle. This matters because an SCR requires stable gas flow rates, NOx concentrations, and temperature to effectively reduce NOx. The temperatures of the EAFs at the BRS/EV facility exhausts will vary widely over the melt cycle, and the gas flow rates, and NOx concentrations will exhibit a wide amplitude, both of which may limit the efficiency of or damage the catalyst in an SCR. Furthermore, an EAF is not a combustion process, but instead primarily relies on electricity to melt metal scrap,[236] meaning that the emission profile of the process is different than the emission profile associated with combustion of fossil fuels, notably including sulfur dioxide and many metals and materials that are incompatible with the SCR, because certain elements present in EAF emissions, such as iron, arsenic, sodium, potassium, nickel, chrome, lead and zinc and potentially others, can react with platinum catalysts to form compounds or alloys which are not catalytically active. These reactions are termed "catalytic poisoning."[237] Furthermore, any solid material in the gas stream can form deposits and result in fouling or masking of the catalytic surface. Fouling occurs when solids obstruct the cell openings within the

changes in the final rule, we reserve the right to challenge application of any such limits or controls to non-EAFs as well since EPA has not shown them to be technically feasible.

[236] While some low NOx natural gas burners are used to support the EAF, the majority of emissions from the process are not attributable to these burners (but rather are attributable to thermal NOx). Accordingly, although low-NOx burners can have a marginal impact on emissions, they can only control a small percent of the EAF's total NOx emissions.

[237] EPA has previously acknowledged this to be an issue. See EPA Comments to Cost Estimate Manual, SCR Chapter, pg. 15 "We agree with the commenter that SCR systems applied to units with high dust loading and high concentrations of sulfur and other compounds may deactivate SCR catalysts and hence increase the capital and operating costs of an SCR."

catalyst. Masking occurs when a film forms on the surface of catalyst over time. The film prevents contact between the catalytic surface and the flue gas. It is infeasible to install an SCR upstream of the baghouse which collects these metals and particulate matter, because the SCR catalyst would be bombarded with all these elements which it is not equipped to handle, reducing its efficiency and at best requiring frequent changing of the catalyst. Furthermore, there may be potential for entrained moisture and or condensable emissions that could be detrimental to the catalyst if a leak were to occur from the tubular section or when temperatures and moisture conditions are unfavorable during cycling of systems. The ability of poisoning and fouling to make SCR technically infeasible is not theoretical. As noted in the attached Black & Veatch report, plugging due to sodium in fluegas has prevented efficient operation of SCR during pilot studies at the Coyote Station in North Dakota, and BRS has high levels of sodium in its fluegas (particulate matter from the EAF captured by the baghouse has 8,080 ppm sodium).[238] And courts have upheld BACT determinations, even in the powerplant context, that SCR is technically infeasible where there are fluegas elements including high levels of sodium and potassium likely to jeopardize SCR operability.[239] This is particularly true of EAFs, which typically have high pre-baghouse particulate matter in the fluegas, as compared to coal fired power plants.

Furthermore, the SCR requires operating temperatures between 480°F (250°C) and 800°F (427°C) of the gas stream at the catalyst bed, in order to carry out the catalytic reduction process. But these temperatures are incompatible with the BRS/EV facility's baghouses which requires the inlet to be dropped down to below 266°F (130°C) or the baghouse could catch on fire. This represents the maximum peak temperature at the spark arrestor prior to the baghouse, with temperatures at other times being far lower accordingly. Furthermore, cooler gas makes the baghouse more effective, since the cooler the gas, the more the metals convert from gas to solid phase preventing them from bypassing the baghouse. In order to regulate the inlet temperature to the baghouse, BRS and EV facilities have cooling systems for the ductwork between each EAF and the associated baghouse. The EAF exhaust temperature must be reduced through a significant length of special tubular water cooled duct i to reduce temperatures sufficiently to avoid damage to downstream components and especially the baghouse. These cooling systems are thus also incompatible with installing an SCR prior to the baghouse since cooling systems must remain to prevent temperatures from compromising the baghouse or interfering with reductions in particular matter, but the resulting cooling results in a temperature outside of SCR operating range.[240]

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[238] See e.g., Energy & Environmental Research Center, EVALUATION OF POTENTIAL SCR CATALYST BLINDING DURING COAL COMBUSTION AND ADD-ON: IMPACT OF SCR CATALYST ON MERCURY OXIDATION IN LIGNITE-FIRED COMBUSTION SYSTEMS, 04-EERC-11-09 (Nov. 2004), available at https://www.wrapair.org/forums/iwg/documents/4FactorComments/2009-05x_SCR_Catalyst_Blinding_final_report.pdf

[239] *See e.g. United States v. Minnkota Power Coop., Inc.*, 831 F. Supp. 2d 1109 (D.N.D. 2011).

[240] Notably this temperature issue also definitively rules out SNCR as technically. infeasible as well, since SNCR requires a far higher operating temperature than even SCR, and an even lower control efficiency. See EPA technical bulletin-Nitrogen Oxides (NOx), Why and How They Are Controlled, at 18, EPA 456/F-99-006R (November 1999) (noting SNCR must be operated at 900°C and 1100°C window).

The only point at which the temperature is not below the operating range of an SCR is the very opening of the EAF duct prior to cooling the fluegas, but that is above the temperature for an SCR (around 1,200 to 1,300°F), and any attempt to cool the temperature at the entrance to the EAF duct, such as through the use of tempering fans, would increase the flowrate through the duct and into the baghouse, which also raises a host of feasibility issues. Specifically, use of tempering fans, and/or any pressure changes caused by the SCR and associated equipment risks jeopardizing the facility's existing pollution control equipment, because the EAFs and pollution control system (baghouse) are designed around specific parameters such as flowrate and pressure drop, and any increase in those parameters could at minimum decrease the life of the bags in the baghouse, and at maximum could result in failure of system components.[241] In addition, the tempering fans, SCR and other new equipment would increase electrical demand at the BRS/EV facility, decreasing efficiency and significantly increasing indirect emissions e.g., NOx, SO2, PM, greenhouse gases, etc. associated with the substantial increase in electricity consumption to operate the SCR and associated equipment and additional flue gas cooling systems, and that assumes that sufficient electric capacity and related equipment to transfer such energy loads is available or otherwise is not in excess of current design capacities.

Critically, as noted in the attached Black & Veatch report, available space is very limited between the EAF and the baghouse and likely would prevent an SCR and associated retrofit equipment being installed anywhere upstream of the baghouse, much less by the entrance to the EAF duct. EPA has previously acknowledged that these spatial constraints can pose obstacles to making an SCR installation work.[242]

Likewise, there are also spacing, and structural design and support limitations that may limit the feasibility of installing an SCR into the stack post-baghouse. Specifically, concrete infrastructure post-baghouse including stack foundation and blower house are substantial installations and the existing as-built design restricts access to the exhaust flow. As noted in the attached Black and Veatch report, there is insufficient space between the ID fan and the stack for the SCR, let alone the booster fan that would likely be necessary to maintain pressure, so any installation would require new structural supports, stack breaching, and the new ductwork would

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[241] Attempting to cool fluegas by injecting water into the flue gas rather than using a tempering fan would be inefficient because this cooling method is already done (BRS) and will be done, once operational (EV) to lower temperatures to protect the baghouse, but the target temperature for cooling the flue gas for the SCR is different than for protecting and ensuring optimum pollution control efficacy of each baghouse and, as a result, the existing system cannot be used for both purposes, and it is not clear whether it would be possible to design the system to accomplish these two different temperature goals solely through water cooling in the space available.

[242] See EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002) at section 2.5.4.2 ("an SCR reactor can occupy tens of thousands of square feet and must be installed directly behind a boiler's combustion chamber to offer the best environment for NOx removal. Many of the utility boilers currently considering an SCR reactor to meet the new federal NOx limits are over thirty years old- designed and constructed before SCR was a proven technology in the United States. For these boilers, there is generally little room for the reactor to fit in the existing space and additional ductwork, fans, and flue gas heaters may be needed to make the system work properly.").

require multiple turns that would increase the pressure drop the booster fan would have to provide, and increase power demands, further exacerbating power capacity issues.

Assuming for the sake of argument that an SCR could be designed to be installed after particulate removal by the baghouse to avoid some of these prohibitive conditions, a different type of technical feasibility problem is entailed, because even if an SCR could be installed, the SCR would risk significantly *increasing* emissions, such that the emissions reductions anticipated would not be possible, or may be much smaller than estimated by EPA. This is because the fluegas exiting the baghouse is typically below 200°F, far below SCR operating range. That means that the fluegas would have to be heated post-baghouse by a significant temperature (at least 300°F in a short period of time), requiring significant additional energy, likely from natural gas combustion and associated electricity needs, which in turn would increase the very NOx emissions the SCR is designed to control, as well as increasing greenhouses gas, VOC, CO, SO2 and PM emissions. These increases may be significant as described in the following section, especially compared to the relatively low NOx reductions an SCR would accomplish even if able to run efficiently.

In addition to any increased emissions caused directly by new combustion sources and indirectly due to increased power consumption, unreacted ammonia would also be emitted to the environment as ammonia slip, as described in the following section. Furthermore, formation of ammonium salts can readily foul the catalyst section, resulting in reduced efficiency and increased back pressure, and ammonium salts would be emitted as PM10/PM2.5. And installation after the baghouse system means that these ammonia and ammonium salt emissions would be completely uncontrolled, creating potential compliance and attainment concerns with the PM2.5 emissions limits and NAAQS, respectively. On the other hand, installation of SCR prior to the baghouse system would contaminate the fly ash in the baghouse with ammonia, and as EPA has recognized, "the ability to sell the fly ash as a secondary product is affected by its ammonia concentration."[243] If this compromises BRS' ability to recycle its baghouse dust by resale to reclamation, recycling, or reuse facilities as is BRS' current practice, then the installation of SCR would create a new unrecycled hazardous waste stream. Furthermore, as EPA has also recognized, "ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heater, ducts, and fans" thus endangering the existing pollution control system.[244]

Additionally, even if SCR technology could be installed post baghouse, the SCR would have issues with catalyst poisoning due to sulfur, as SO2, reacting with the SCR regardless of the placement of the SCR (impeding technical feasibility) unless desulphurization technology can also be installed (which would entail both its own set of technical feasibility issues in addition to significant additional costs not considered by EPA).

Furthermore, as discussed in the attached Black & Veatch report, stack testing at the U. S. Steel BRS facility shows a NOx concentration in fluegas near the lower limit of what concentration can be controlled by an SCR. According to EPA's own analyses, "Low NOx inlet levels result in

[243] EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002) at section 2.2.6, page 2-28.

[244] EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002) at section 1.2.3, page 1-12.

decreased NOx removal efficiencies"[245] an SCR is generally only expected to control 70% of emissions at a part per million ("ppm") loading as low as 20 ppm (putting aside temperature, fouling, poisoning, plugging, and other such issues which could decrease efficiency and/or degrade the catalyst). [246] And we are unaware of any vendor that will guarantee removal efficiency at all much below 5 ppm NOx. These limitations on control efficiency are further exacerbated by the temperature issue, since temperatures on the low end of SCR operability also significantly decrease SCR efficiency as compared to higher temperatures.[247]. Given the combination of very low NOx concentration loadings, and low temperatures, the control efficiencies presumed by EPA in the Proposed Rule are simply not technically feasible.

C. Emission Increases Associated With Installation of SCR.

Based on the engineering review conducted by Black & Veatch and discussed above, the exhaust gas temperature from an EAF, prior to the dedusting baghouse / after the baghouse, is the vicinity of 200 degrees Fahrenheit (F), thus requiring additional equipment to be installed to raise the exhaust gas temperature by at least 300 degrees F to reach the minimum operability range of 500 degrees F for an SCR, as would be required for just 50% NOx removal efficiency (not taking into account the NOx concentration, airflow variability, and poisoning/fouling/plugging issues discussed above). To support reheating of the exhaust gas by an additional 300 degrees F will require the installation of a heating devices, which will consist of the installation / operation of a natural gas fired burner(s).

The amount of energy required to heat the EAF dedusting exhaust air by 300 degrees F can be calculated with the following equation:

- British Thermal Units (BTU) Output = Temperature rise multiplied by (X) cubic feet per minute X BTU per pound per degree F X the density of air at 200 degrees F X 60 minutes per hour.
    - Temperature rise required is 300 degrees F.
    - Exhaust gas flow from an EAF is on average approximately 1,300,000 standard cubic feet per minute (SCFM) from a dedusting system. Actual flow rate (ACFM) does vary based on temperature and other parameters.
    - Specific heat of air at 200 degrees F is 0.24 BTU per pound per degree F.
    - The weight per cubic foot of air is 0.061 (pounds / cubic foot)(lbs/ft3)).
- BTU Output = 300 degrees F. X 1,300,000 cubic feet per minute X 0.24 BTU per pound, per degree X 0.061 lbs/ft3 X 60 minutes / hour = 342.5 MMBtu/hour.

[245] EPA Air Pollution Control Cost Manual, edition 7 (June 2019) at section 2.2.2.

[246] EPA, Clean Air Technology Center Products, Air Pollution Technology Fact Sheet: Selective Catalytic Reduction (2003), available at https://www.epa.gov/catc/clean-air-technology-center-products.

[247] EPA Air Pollution Control Cost Manual, edition 7 (June 2019) at section 2.2.2 figure 2.2.

To generate the 342.5 MMBtu/hour needed to heat the exhaust gas by 300 degrees F, and assuming the heating value of natural gas is 1,000 BTU per cubic foot, you would need 342,500 cubic feet per hour of natural gas. Combusting that additional natural gas will cause a release of NOx emissions (among other pollutants) during the process of combusting that natural gas in the heating burner(s).

The amount of NOx emissions that can occur when combusting 342,500 cubic feet of natural gas can be calculated using the AP-42 emission factors EPA has published for the purpose of calculating emissions of pollutants from combustion of natural gas.[248] An emission factor is a representative value that attempts to relate the quantity of an air pollutant released to the atmosphere with an activity associated with the release of that air pollutant. These factors are usually expressed as the weight of air pollutant divided by a unit weight, volume, distance, or duration of the activity emitting the pollutant (e. g., kilograms of particulate emitted per megagram of coal burned). Such factors facilitate estimation of emissions from various sources of air pollution. In most cases, these factors are simply averages of all available data of acceptable quality and are generally assumed to be representative of long-term averages for all facilities in the source category (i. e., a population average).

Section 1.4 of AP-42 provides emission factors for quantifying the emissions of NOx, as well as other regulated air pollutants based in the combustion of natural gas expressed in either pounds per MMBtu or pounds per standard cubic foot of natural gas combusted. Tables 1.4-1 and 1.4-2 provided emission factors for various regulated air pollutants. Those emission factors are summarized in the table below:

Combustion type	**Regulated Air Pollutant**	**Emissions Factor (lb/10^6 standard cubic foot)**
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Oxides of Nitrogen (NO_x)	140
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Carbon Monoxide (CO)	84

[248] See "Compilation of Air Pollutant Emissions Factors – Volume I: Stationary Point and Area Sources", dated January 1995. The Emission Factor And Inventory Group (EFIG), in the U. S. Environmental Protection Agency's (EPA) Office Of Air Quality Planning And Standards (OAQPS), develops and maintains emission estimating tools used in developing emission control strategies, determining applicability of permitting and control programs, ascertaining the effects of sources and appropriate mitigation strategies, and a number of other related applications. The AP-42 series is the principal means by which EFIG can document its emission factors. These factors are cited in numerous other EPA publications, and electronic data bases, but without the process details and supporting reference material provided in AP-42 and are generally relied on by EPA when source specific testing or CEMS are unavailable.

Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Carbon Dioxide (CO_2e)	120,000
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Particulate Matter <2.5 Microns ($PM_{2.5}$)	7.6
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Sulfur Dioxide (SO_2)	0.6
Large Wall-Fired boilers – Controlled With Low NOx Burners, > 100 MMBtu / Hour Heat Input	Volatile Organic Compounds (VOCs)	5.5

To estimate the potential emissions of the above listed regulated air pollutant, the emission factor expressed in pound per million cubic standard feet of natural gas is multiplied by the quantity of natural gas combusted in an hour to get pounds of that air pollutant per hour and then the amount of natural gas consumed in a year to get pounds per year or commonly expressed as tons per year. Provided in the table below is an estimate of the additional air pollutants that would be released in the atmosphere based on installation of natural gas burners to heat the EAF exhaust air by 300-degree F, to allow for SCR to operate at even minimum effectiveness.

Regulated Air Pollutant	**Emissions Factor (lb/10^6 standard cubic foot)**	**Estimated million (10^6) standard cubic ft per of hour of Natural Gas)***	**Estimated Lbs Per Hour Emission Rate**	**Estimated Tons Per Year****	**Estimated Tons Per Ozone Season*****
Oxides of Nitrogen (NO_x)	140	0.3425*	47.95	210.0	87.5
Carbon Monoxide (CO)	84	0.3425*	28.77	126.0	52.5
Carbon Dioxide (CO_2e)	120,000	0.3425*	41,100	180,018	75,007.5
Particulate Matter <2.5 Microns ($PM_{2.5}$)	7.6	0.3425*	2.6	11.4	4.75
Sulfur Dioxide (SO_2)	0.6	0.3425*	0.21	0.92	0.38

Volatile Organic Compounds (VOCs)	5.5	0.3425*	1.88	8.23	3.4

* As noted above the amount of natural gas estimated on an hourly basis to heat exhaust gas up by 300 degrees F is 342,500 standard cubic feet per hour. Expressed in lbs/106 standard cubic foot would be 0.3425 lbs/million standard cubic foot.

** Assumes operation 24 hours a day 365 days per year.

***Tons per year multiplied by 5/12 to reflect five months of ozone season.

It is important to note, that the above estimated emissions of regulated air pollutants are additional amounts of these air pollutants that would be generated / released to the atmosphere based on the required heat the EAF dedusting exhaust gas by 300-degree F to allow for SCR to operate. An additional 250-degree F raise in the temperature would be required so that the SCR could operate at the optimum temperature (i.e., to achieve a 90% reduction in NOx emissions), which is around 750-degree F in NOx emission levels. The amount of energy required to raise that temperature would require the natural gas volume to be increased by almost a factor of two. In that case, the projected emissions rates would also increase by a factor of approximately two. Note also that this is an estimate of the increased air pollutant emissions per EAF and would thus need to be multiplied by each EAF to which SCR is applied which for the case of the BRS/EV facility, would be four (4) times to reflect four (4) EAFs.

Notably, as explained elsewhere in these comments, the Proposed Rule would decrease the permitted lb/ton NOx rate for each of the BRS/EV EAFs by up to 50% by reducing the current permit limit of 0.3 lb/ton to the Proposed Rule limit of 0.15 lb/ton. At a presumed capacity of 250 tons/hr for each EAF, times 3,672 hours per ozone season, that represents a reduction of up to 137,700 lb (i.e., 68.85 ozone season tons) per EAF. Comparing these maximum potential reductions (68.85 ozone season tons) to the potential NOx increases (87.5 ozone season tons), it appears that the changes to an EAF dedusting exhaust gas temperature necessary to enable SCR to function could be even higher than the potential NOx reductions achieved by installation of an SCR units at the BRS/EV facility.

In addition to emission increases associated with installation of natural gas fired burners needed for EAF dedusting exhaust gas heating, the ammonia slip associated with SCR installation would cause the release of ammonia emissions (in the form of particulate matter) from each EAF, which are typically not associated with dedusting exhaust gases. The term slip implies that not all of the ammonia used in the SCR system chemically reacts to reduce the presence of NOx in the dedusting exhaust air. EPA's own estimates suggest that SCR can be associated with 2 to 10 ppm ammonia slip, and even a well-functioning SCR would have ammonia slip of 2 to 5 ppm, with ammonia slip increasing as catalyst activity decreases, as it might be expected to occur given the range of feasibility issues entailed in installation on an EAF, including the high temperature variability and airflow variability, and poisoning/fouling/plugging issues.[249]

Using an estimate of 5 ppm ammonia slip due to the factors outlined above, a general estimate of the quantity of ammonia slip can be estimated as follows:

- Appendix A to AP-42 provides the following equation for converting ppm by volume to pounds per cubic foot: M/385.1 X $10(^6)$, where M= Molecular weight of gas. Molecular weight of ammonia is 17.03. Thus 1 ppm ammonia = 17.03/385.1 x $10(^6)$ = <u>4.42 x. $10(^{-8})$ lb ammonia/ft^3</u>
- Thus, 5ppm ammonia slip = 5 x. 4.42 X $10(^{-8})$ lb/ft^3 = 22.1 X $10(^{-8})$ lb/ft^3
- Exhaust gas flow from an EAF is on average approximately 1,300,000 scfm. Actual flow rate does vary based on temperature and other parameters. Multiplying this per minute flowrate by 60 yields a per hour flowrate of 78,000,000 standard ft^3/hour (hr).
- Thus, 22.1 X $10(^{-8})$ lb/ft^3 X 78,000,000 ft^3/hr = 17.238 lb of ammonia slip per hour.

Assuming operation only during the ozone season, 17.238 lbs/hr X 8760 hrs/year (yr) x. 5/12 ozone months/ year X 0.0005 ton/lb = 31 tons of ammonia per ozone season per EAF. Notably, if the SCR was installed downstream of the baghouse, this would be uncontrolled emissions, and would increase PM2.5, since ammonia is recognized to be a significant precursor to secondary particulate matter emissions.[250] In fact, some studies have suggested that reducing ammonia emissions to reduce condensable particulate matter is more cost effective than NOx reductions.[251] On the other hand, if installed upstream of the baghouse, any portion not emitted would contaminate the baghouse dust that is currently recycled/reclaimed by a third party, potentially creating a new and significant hazardous waste stream.

Taken together, the increased NOx emissions from dedusting exhaust air heating and ammonia (i.e., particulate matter) emissions from ammonia slip would negate any environmental value of the SCR given the equivalent or smaller amount of NOx the SCR would be capable of

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[249] EPA Air Pollution Control Cost Manual, edition 6, EPA/452/B-02-001 (Jan. 2002), at section 2.2.2, page 2-13.

[250] See e.g., Plautz, Ammonia, a poorly understood smog ingredient, could be key to limiting deadly pollution (2018), available at https://www.science.org/content/article/ammonia-poorly-understood-smog-ingredient-could-be-key-limiting-deadly-pollution; Wang, S., Nan, J., Shi, C. *et al.* Atmospheric ammonia and its impacts on regional air quality over the megacity of Shanghai, China. *Sci Rep* **5,** 15842 (2015), available at https://doi.org/10.1038/srep15842 ; Behera, S. N. & Sharma, M. Investigating the potential role of ammonia in ion chemistry of fine particulate matter formation for an urban environment. Sci. Total Environ. 408, 3569–3575 (2010), available at https://www.sciencedirect.com/science/article/abs/pii/S0048969710003955; Yiyun Wu, Baojing Gu, Jan Willem Erisman, Stefan Reis, Yuanyuan Fang, Xuehe Lu, Xiuming Zhang, PM2.5 pollution is substantially affected by ammonia emissions in China, Environmental Pollution, Volume 218, p.86-94 (2016), available at https://doi.org/10.1016/j.envpol.2016.08.027.

[251] Baojing Gu, Lin Zhang, *et al.* "Abating ammonia is more cost-effective than nitrogen oxides for mitigating PM2.5" Science, v.374 no. 6568, p.758-762 (2021), available www.science.org/doi/abs/10.1126/science.abf8623

reducing from each EAF. This demonstrates that SCR installation is not a technically feasible means of decreasing NOx from EAFs by ~50% as would be required to meet the limits in the Proposed Rule and requiring SCR in the face of these realities is arbitrary and capricious.

Finally, it should be noted that unlike SCR retrofits in the powerplant sector where increased air pollution emissions associated with installation of an SCR (both ammonia slip and emissions from heating or cooling fluegas) could be outweighed by even a marginal percentage reduction of NOx given the magnitude of NOx emissions at EGUs (thousands to tens of thousands of tons of NOx per year), in non-EGU contexts like those in the steel industry where EPA proposes to require SCR at units as small at 100 tons per year of NOx, the magnitude of NOx reductions that could be achieved by SCR is simply not significant next to the increased air pollution emissions associated with installation of an SCR. Under these circumstances, SCR is infeasible from an emission reduction perspective because the smaller decreases in NOx associated with SCR at a unit with only a few hundred tons of potential emissions NOx could be significantly offset or even swallowed by electrical consumption of the SCR and its related equipment (indirect emissions) as well as increased emissions from fluegas heating or the increased indirect emissions associated with an increase in energy consumption associated with flue gas cooling equipment, both of which would significant heat/electrical input due to the conditional dynamics required in such short distances.

XVIII. EPA's Cost Analysis Is Arbitrary and Unreasonable as Applied to EAFs, and Especially to Those in Arkansas

A. EPA Fails to Provide Any Cost Estimates Specific to EAFs, Despite Taking Cost Into Account For Other Types of Emission Units

EPA has not provided a cost-analysis specific to EAFs. Instead, EPA provides a generalized estimate $4,345/ton for SCR installation in the broad industry of "Iron and Steel Mills and Ferroalloy Manufacturing." In the first place this generalized aggregation is inappropriate because, as EPA has previously recognized, EAFs are distinct from both ferroalloy production and from other types of steel production such as integrated iron and steel mills.[252] Furthermore, EPA's failure to examine SCR installation on steel mill EAFs is particularly inadequate in light of EPA's

[252] E.g., 57 Fed. Reg. 31,576, 31,582, 31,591 (July 16, 1992) (after determining to "list broad categories of major and area sources rather than very narrowly defined categories," listing Ferroalloy Production, Integrated Iron and Steel Manufacturing, and Electric Arc Furnace Operation as wholly separate source categories under section 112 of the CAA); 39 Fed. Reg. 37,466 (Oct. 21, 1974) (When first proposing CAA Section 111 new source performance standards for EAFs, differentiating EAFs from "old open hearth furnaces"); Background Information for Proposed New Source Performance Standards: Asphalt Concrete Plants, Petroleum Refineries, Storage Vessels, Secondary Lead Smelters and Refineries, Brass or Bronze Ingot Production Plants, Iron and Steel Plants, Sewage Treatment Plants - Volume 1 Main Text at 49, APTD-1352 (June 1973) (As part of docket supporting first NSPS standards for Iron and Steel Plants, eventually published at 39 Fed. Reg. 9308, differentiating between production via "Basic oxygen process; operation of open hearth, blast, and electric furnaces" and stating "The proposed standards would only apply to basic oxygen process furnace"); Background Information for Standards of Performance: Electric Arc Furnaces in the Steel Industry Volume I: Proposed Standards, at 1-4, EPA-450/2-74-017a (1974) (when first setting an NSPS standard for EAFs, differentiating between electric arc furnaces, basic oxygen process, open hearth steel production furnaces, blast furnaces, and coke and sintering plants).

recent declaration that that emission units "must be assessed on an individual basis to determine whether SCR is a feasible control technology based on its site-specific characteristics and the SCR technology available at the time."[253] By failing to conduct any feasibility or cost analyses regarding EAFs, EPA has impermissibly "failed to rely on its own judgment and expertise."[254] If EPA still maintains that units "must be assessed on an individual basis," then it has an obligation to do so. And if EPA no longer stands by that position, it has an obligation to justify its departure from prior policy. EPA has done neither, impermissibly attempting to "depart from prior policy *sub silentio*."[255]

Not only is the cost analysis devoid of any data pertaining to the installation of SCR controls on EAFs, EPA's modeling of cost/ton estimates for SCR did not even include any EAFs at any site in its cost analysis.[256] The Proposed Rule's assertion that EAFs can install SCRs below the cost threshold of $7,500 per ton of NOx is unsupported by the screening assessment on which EPA purports base its assumptions. Furthermore, EPA's own Control Cost Manual in the docket admits that the cost estimates provided <u>are not applicable to non-EGUs</u>, stating that "The procedures to estimate capital costs are not directly applicable to sources other than utility and industrial boilers"[257] and "Due to the limited availability of equipment cost data and installation cost data, the [EPA's Integrated Planning Model EGU specific] equations for SCR capital costs were not reformulated."[258]

Accordingly, as currently composed the Proposed Rule is in clear violation of EPA's obligation to "reflect upon the information contained in the record and grapple with contrary evidence,"[259] and to promulgate internally consistent rules.[260] An agency decision is arbitrary and capricious where, as here "the agency has failed to 'examine the relevant data' or failed to 'articulate a rational explanation for its actions.'"[261]

B. EPA Significantly Underestimates Costs Associated with SCR Installation on an EAF:

Even if one incorrectly assumes that it is feasible to install SCRs on EAFs, there are several reasons why costs will be significantly greater than claimed by EPA, for example:

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253 EPA Comments to Cost Estimate Manual, SCR Chapter, pg. 9 (emphasis added).

254 *Am. Lung Ass'n v. EPA*, 450 U.S. App. D.C. 385, 415, 985 F.3d 914, 944 (2021).

255 *FCC v. Fox TV Stations, Inc.*, 556 U.S. 502, 515-16, 129 S. Ct. 1800, 1811 (2009).

256 Non-EGU Screening Assessment at Table 6.

257 Control Cost Manual at 6.

258 *Id*. At 65.

259 *Fred Meyer Stores, Inc. v. NLRB*, 865 F.3d 630, 638, 431 U.S. App. D.C. 283 (D.C. Cir. 2017).

260 *Hsiao v. Stewar*t, 527 F. Supp. 3d 1237, 1252 (D. Haw. 2021), quoting *Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1141 (9th Cir. 2015) ("[A]n internally inconsistent analysis is arbitrary and capricious.").

261 *Genuine Parts Co. v. EPA*, 890 F.3d 304, 311-12, 435 U.S. App. D.C. 338 (D.C. Cir. 2018) (quoting *Carus Chem. Co. v. EPA*, 395 F.3d 434, 441, 364 U.S. App. D.C. 339 (D.C. Cir. 2005)).

1. If it were possible to install SCR on EAFs, as noted above, it would require the addition of various systems and equipment to heat and/or cool the exhaust steam, and to reduce pre-baghouse particulate matter loading, and require significant re-engineering of entire air pollution control systems to ensure compatibility and functionality. The cost for this new equipment is not currently accounted for in EPA's cost estimates for SCR installation at EAFs, and as noted in the attached memo from Black and Veatch, these costs are significant.
    a. As noted in Black & Veatch's report, even if one incorrectly assumes that it is technically feasible to install an SCR between the EAF and the baghouse (e.g., catalyst poisoning/plugging/fouling, available space, temperature issues, etc.), the costs installed costs associated with that equipment, whether it is a tempering air system or a spray duct water system are significant, with installed costs (minimally without the benefit of more detailed engineering) of at least $11.7 million and $11.2 million, respectively, for each EAF at the BRS/EV facility (not accounting for ongoing operation and maintenance costs, including increased electricity consumption).
    b. A duct burning system to heat the flue gas after the baghouse likely would cost upwards of $27,800,000 just to install the burners necessary to sufficiently heat the fluegas for SCR to be operable, without even accounting for ongoing operation and maintenance costs, including increased utilization of natural gas).
2. Increased emissions as a result of such heating fluegas in turn would increase SCR costs because the size of the SCR system would need to be increased to reduce these newly introduced emissions. Note also that further NOx controls would be required by third parties to offset indirect NOx emissions associated with indirect emissions associated with electricity demand associated with the operation of the SCR as well as any flue gas cooling system.
3. In order to reduce the large temperature fluctuations throughout the EAF process that might otherwise be destructive to the catalyst, equipment would have to be installed to balance the temperature. Such equipment is not accounted for in EPA's cost estimates for SCR installation at EAFs.
4. In order to reduce inconsistencies in gas flow given the batch nature of the process, additional equipment would have to be installed to level out the velocity of the flue gas and increase it during certain process periods in order for it to flow through the SCR at a reasonable and consistent rate. This new equipment is not accounted for in EPA's cost estimates for SCR installation at EAFs.
5. CEMS are very expensive and EPA specifically says it did not include them in the cost efficiency estimates. More specifically, based on customer-friendly industry quotes obtained by Black & Veatch, installation of a single CEMS system at a single EAF would cost at least $300,000 in capital expenditure. Installation and certification would be at least

an additional $100,000. Annual O&M costs just from a Preventative Maintenance contract would cost at an additional $100,000 per year. These costs do not reflect contingencies that often arise during retrofit CEMs projects. The Proposed Rule would require at least four CEMS units (one for each EAF) at the U.S. Steel BRS and EV facilities in Arkansas.

6. EPA's cost estimates have not been inflation adjusted to 2022 dollars. In addition to inflation, the new normal in the wake of a national pandemic and its havoc on industry has resulted in persistent supply chain issues, which further drives costs. And supply chain issues and associated costs will only be exacerbated by any rule requiring everyone in the industry to purchase and install the same equipment. In light of these factors, it is inappropriate to use older cost estimates without any attempt to adjust anticipated costs to reflect the new normal.

7. Actual studies have been performed to account for the full costs associated with SCR retrofits in the EGU sector suggesting that design, equipment, and installation cost upward of $50 Million in 2006 dollars,[262] or approximately $66 Million in 2021 dollars.[263] Although these cost estimates were for EGUs, they are the only cost estimates available for real world retrofit costs since the technology has never been demonstrated on an EAF. In fact, if possible at all, as noted above, modifications not typically needed at a power plant, such as significant flue gas heating or cooling would be required, so it is reasonable to expect that costs could be higher than these estimates associated with SCR retrofit at an EGU (though EPA has never to our knowledge attempted to estimate costs associated with retrofitting an EAF with SCR, perhaps because it has never been deemed technically feasible as would be consistent with EPA's express statements and determinations prior to the Proposed Rule). At the BRS and EV facilities, the control efficiency required for EAFs in the Proposed Rule would only yield a maximum (potential) NOx reduction of 68.85 ozone season tons from each EAF. The actual NOx reductions achieved would, in reality, be significantly less than this figure since this figure assumes 24/7/365 production at the highest permitted emission rate and throughput from the EAFs which is not a realistic assumption given actual observed NOx emissions and periodic and planned outages for routine maintenance.

8. A study of actual operation and maintenance cost by Electric Power Research Institute found that O&M for an SCR can cost upwards of $2 Million/year.[264] Accordingly, under the extremely conservative assumption of 68.85 ozone season tons per EAF/SCR, this O&M estimate, taken alone, would translates to a cost of $29,049 per ozone season ton

[262] POWER, "Estimating SCR Installation Costs" (Feb. 15, 2006) (discussing EUCG inc. survey of 72 power plants, showing avg cost of 170/Kw for plants in the 300MW range.

[263] Based on CPI Inflation Calculator, available at https://www.bls.gov/data/inflation_calculator.htm (comparing January 2006 dollars to January 2021 dollars).

[264] Electric Power Research Institute, "Operation and Maintenance Costs for Selective Catalytic Reduction Systems" (Technical Update, December 2017).

reduced[265], almost four times EPA's cost effective threshold of $7,500 in the Proposed Rule; and this figure only accounts operation and maintenance, not including the additional significant annualized portion of the initial SCR installation cost.

9. Because of the very different types of ducts required for each EAF, limitations on space available, the designs of these duct systems, the exhaust conditions, temperature delta between them, it is not unreasonable to presume that multiple systems (more than just one tempering or duct burner and SCR unit per EAF unit) may be required in order to achieve predictable repeatable conditions required for the SCR to perform its function without risk of damage to it or other systems.

10. Any retrofit that involves the pollution control system will require operational shutdown for during certain time periods due to system designs and interdependencies, and since the facility cannot legally operate without venting to the pollution controls, and the resulting outage cost from a retrofit could be catastrophic to the iron and steel industry. Notably, steel production is unlike an electric utility with an obligation to provide power 24/7/365 under the worst conditions and therefore has planned accordingly by having a large fleet of electricity units (or contracts with such units) that can be ramped up to replace power during outages. This extended downtown also could result in significant financial implications as electricity and natural gas supply contracts require payment regardless of use. During the months that will likely be needed to ensure equipment and pollution control devices are operational and that all technological retrofits and changes needed have been made, there will simply be no steel production. The Proposed Rule clearly does not consider or contemplate these issues.

C. Cost Annualization Should Account for Fact that Reductions are Not Needed After 2028 in Arkansas.

If EPA does not adjust compliance obligations for Arkansas non-EGU's based on White Bluff's imminent closure, as discussed above, then in the alternative, EPA must at minimum correct the cost analysis to account for the fact that any emission reductions from non-EGUs in Arkansas are only needed for a maximum of two years (2026 and 2027), due to the closure of Entergy's White Bluff coal plant in 2028, since any reductions from non-EGUs beyond that point are unnecessary in order to ensure downwind attainment based on EPA's modeling.[266] Accordingly, the cost of SCR installation at Arkansas non-EGUs should only be annualized over that two year period which is the only period it is legally relevant, rather than annualized over the life of the equipment. Based on the costs estimates derived from EGUs discussed above, this would result in an theoretical, estimated cost per ton calculation for SCR installation at U. S. Steel's BRS and EV facilities of $479,303/ton of NOx reduced per EAF, not even accounting for O&M costs

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[265] $2,000,000 / 68.85 tons = $29,049.

[266] See above discussion regarding amount of White Bluff emissions versus the amount of reductions EPA modeled from non-EGUs as a result of the Proposed Rule.

or the other technical impediments discussed in this Section .[267] Given the massive cost per ton associated with such a scenario, EPA should instead consider more cost effective short term methods in Arkansas for the 2026 and 2027 ozone seasons and should coordinate with the State of Arkansas in the selection and implementation of such methods.

SPECIFIC COMMENTS PERTAINING TO BY-PRODUCTS COKE MAKING FACILITIES

XIX. EPA Miscategorizes and Fundamentally Misunderstands By-Products Coke Making; and Misapplies Emissions and Technologies to the Process

EPA failed to perform any coke making stakeholder engagement whatsoever in advance of the Proposed Rule. This lack of stakeholder engagement has contributed to EPA's failure to understand the by-product coke making process. The docket associated with the Proposed Rule is extremely light on any technical support for the proposed NOx limits to charging and pushing, and it is apparent that what little information is provided in the docket is not representative of the by-products coke making process. In its rush to regulate, EPA is relying on scant information from heat recovery coke making which is fundamentally different and not representative or applicable to by-products coke making. Furthermore, and most significantly, there are several inconsistencies throughout the Proposed Rule.

U. S. Steel has one remaining coke plant in its footprint – consisting of ten by-products batteries - that is critical to our integrated operations and the domestic iron and steel making industry as a whole. The Clairton coke plant ("Clairton Plant") provides coke to U. S. Steel facilities with blast furnaces as well as third parties – all that are located off-site, and are separate from the Clairton Plant (i.e., the Clairton Plant is not co-located with any blast furnaces.) The facility is the largest coke making facility in North America and is subject to the most stringent air pollution control regulations in the county, according to the Allegheny County Health Department ("ACHD") who has been delegated authority to regulate air pollution sources in Allegheny County from EPA and the Pennsylvania Department of Environmental Protection. After several BART and RACT evaluations over decades, never has EPA, PADEP or ACHD determined that SCR was a suitable or appropriate technology for charging or pushing activities associated with the coke making process. Never before has any of the agencies asserted that charging coal into coke ovens was a significant source of NOx. To the contrary, in AP-42, EPA acknowledges that NOx emissions from charging are not significant.[268] Furthermore, in applying BACT to C Battery in 2012, ACHD determined that SCR was not appropriate.

In the Proposed Rule, EPA upends and departs from years of prior precedent and knowledge with a couple of ambiguous, and even illogical, paragraphs.[269] Yet, this proposed

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[267] ($66 Million / 2 years) / 68.85 ozone season tons per year = $479,303/ton.

[268] https://www.epa.gov/sites/default/files/2020-11/documents/c12s02_may08.pdf

[269] See page 44 of the Non-EGUs Sectors TSD, where EPA attempts to justify the proposed limits for coke plants with nothing more than: "For coke ovens (charging) and coke ovens (pushing), EPA based the emission limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50% based on current

technology has not been shown to be available or feasible for these emission sources. While we have many concerns over the Proposed Rule as it would apply to coke batteries, the first overarching comment, as a general matter, is that the Clairton Plant is NOT integrated physically with any iron and steel facilities (e.g., blast furnaces, basic oxygen furnaces, etc.) The facility is a physically separated form and is not part of any "stationary source" consisting of U.S. Steel's integrated iron and steel facilities and operates under the NAICS code 3241, "Petroleum and Coal Products Manufacturing." Thus, grouping coke in the iron and steel sector is inappropriate – especially when Congress and EPA have historically considered the processes unique and separate in other rulemaking efforts. If the coke industry were properly classified in the NAICS code 3241, the charging and pushing would not be included - which is much more logical than what EPA attempts to do in the Proposed Rule.[270]

Second, the Proposed Rule, as it applies to charging at coke plants, is inconsistent and illogical. As noted above, the NAICS code of 3311 is not applicable to stand-alone coke plants. In addition to this inconsistency (where EPA categorizes coke into NAICS code of 3311), in Table I.B-4 of the Proposed Rule, EPA proposes a NOx charging limit of 0.6 lbs/ton of coal charged for coke ovens (charging *and coking*). However, the reference to including "coking" and the 0.6 lbs/ton of coal charged limit is not explained or supported in the Non-EGU Technical Support Document (TSD). Furthermore, it is unclear as to what aspect of the "coking" process EPA intends to regulate, where it intends to regulate, and how it intends to regulate "coking" as noted in this Table – as the docket is void of any supporting information. To add further inconsistencies, in the TSD, EPA attempts to explain the process, but by doing so, it creates additional ambiguities:

> "Often situated in front of a bank of coke ovens, *a separate machine is responsible for opening the coke oven doors, charging and pushing the raw material, and closing the oven again. This machine is often termed a larry car, or charging and pushing machine, among other terms."* [271]

This statement does not accurately describe charging and pushing in a by-products coke oven. While a larry car is used in by-products ovens, it is separate and distinct from pushing and is *done at the top of the oven*. Thus, in a by-products battery, a weighed amount or specific volume of coal is discharged from the bunker into a larry car - a charging vehicle that moves *along the top of the battery*. The larry car is positioned over the empty, hot oven (called "spotting"), the lids on the charging ports are removed, and the coal is discharged from the hoppers of the larry car into the oven. To minimize the escape of gases from the oven during charging, steam aspiration is used

permit emission limits and production-based push/charge cycles. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices."

[270] See, e.g., NESHAP MACT for coke making (Subpart CCCCC) which is separate from NESHAP MACT for integrated iron and steel (Subpart FFFFF)

[271] Page 24 of Non-EGU TSD.

at most plants to draw gases from the space above the charged coal into a collecting main. In addition, charging is not known to emit any appreciable amounts of NOx. It is also not clear on how one would install and operate an SCR on a moveable larry car as EPA seems to propose.

The inconsistencies and ambiguities do not end there. In the TSD, EPA attempts to explain:

> "For coke ovens (charging) and coke ovens (pushing), EPA based the emission limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50% based on current permit emission limits and production-based push/charge cycles. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices."

Yet, the on-line version of AP-42 refers to a NOx emission factor for charging of 0.03 lb/ton of coal charged, not the 0.3 lb/ton referenced in the preamble of the Proposed Rule, where EPA explains that the proposed NOx limit of 0.15 lb/tons of coal charged is based upon an assumption of "50% reduction staged combustion and/or limited use SCR/SNCR during charging operations from AP-42 0.3 lb/ton emission factor." It is unclear if EPA's reference to 0.3 is in error; or if the AP-42 emission factor is in error. In any case, clarification is needed.

It is significant to note, too, that according to the non-EGU TSD, EPA's proposal assumes a projected reduction efficiency of 40-50% based on current permit emission limits and production-based push/charge cycles; and that EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices. While EPA makes these very broad assumptions and conclusions on the expected reductions on one hand, on the other hand, in the non-EGU TSD, EPA acknowledges that, "coke ovens with NOx controls in the United States have not been found." Yet, EPA, for the first time, is proposing sweeping NOx controls across coke plants in the United States under the guise of its authority under the Clean Air Act to address interstate transport of pollutants.

It is important to add, that overall, the NOx emissions from charging and pushing are minimal and any emissions control equipment installed would result in minimal NOx reductions. Most importantly the application of SCR technology is not feasible from a technical perspective and, even if assuming it was, is not economically feasible, particularly in light of EPA's limited legal authority in the Proposed Rule to impose only controls necessary to mitigate significant contribution to nonattainment or interference with maintenance without any overcontrol. It also would substantially increase other pollutants. Work produced by Trinity Consultants shows:

> "Trinity calculated cost effectiveness for potential application of SCR at the Clairton C Battery coke pushing, after the baghouse. The minimum annual cost effectiveness would

be $271,472/ton (2021$), with 72 tons of NO_X formed from combustion of natural gas to reheat the exhaust gas steam compared to approximately 92 tons from the unit itself, as well as approximately 87,000 tpy of CO_2."

These numbers clearly show how the application of SCR to coke ovens is not a cost-effective approach and should not be required. This is yet another example of the Proposed Rule not accurately reflecting the costs of implementation and overstating the potential NOx reductions.

In addition, it is unclear as to what coke plants would even be subject to the rule because the two types of emission units at coke plants that would be subject to the rule are (1) coke ovens (charging) and (2) coke oven push cars and pushing-charging machines (pushing). Based upon the description of the "emission unit" in the proposed rule and the applicability, it would appear that no coke oven (or coke battery, for that matter) would be subject to the proposed limits because the PTE at these two sources are well below 100 tons.

U. S. Steel also respectfully notes that it is unclear on how EPA's modeling incorporates NOx reductions that would be achieved through these NOx emission limits. For example:

- In the pre-FIP model, what inputs did EPA consider from coke plants?
- How were these relatively insignificant sources of NOx emissions shown to contribute or interfere with ozone nonattainment in downwind receptors?
- How did EPA show that the proposed controls for these units would result in any measurable improvement in ozone concentrations monitored at n downwind nonattainment receptors?

For the reasons explained above, U. S. Steel respectfully contends the Proposed Rule is fatally flawed because the emission estimates and projected reductions are not legally or technically supported by anything in the docket – and we further contend that this is because the Proposed Rule as it applies to coke plants is indeed unsupportable by fact or law.

SPECIFIC COMMENTS PERTAINING TO INTEGRATED STEEL MAKING OPERATIONS

XX. Summary of Overarching Concerns

As explained in more detail throughout and below, we have the following overarching concerns with the Proposed Rule as it relates to U.S. Steel's integrated steelmaking operations:

1. Due to numerous fatal flaws and fundamental errors in the proposed rule, EPA must re-evaluate ozone impacts from the iron and steel industry to determine if they do indeed interfere with ozone attainment in downwind states; and only if it is shown that such interference does occur and only after State are afforded ample opportunity to correct any SIP deficiencies, issue a revised proposal with requisite supporting information for the Good Neighbor FIP for the steel industry.

2. The comment period was entirely insufficient and unjustified as EPA supporting documentation is very scant for many emissions units and their respective proposed limits.

3. The docket is missing numerous critical files to evaluate EPA's proposal. Providing the critical files for stakeholder review and comment is needed for stakeholders to provide comments.

4. There was insufficient time to conduct a robust review of the air quality modeling and to conduct an independent modeling analysis, especially in light of the fact that it took several days after the public comment period for EPA to provide stakeholders with the requested modeling files – inappropriately abbreviating an already entirely too short comment period. The files should have been public available on Day One of the comment period.

5. EPA inappropriately uses a 1% (0.7 ppb) threshold rather than the 1 ppb threshold that EPA previously provided States as an appropriate threshold to determine potential NAAQS interference. In short, EPA provided guidance to States (and the regulated community and other stakeholders) and then rejected SIPs that relied on that guidance, and, instead, replaced it with a lower triggering threshold to supplant state's engagement and primacy in the implementation of the Clean Air Act requirements as Congressed intended.

6. The docket does not have the requisite information to support a finding that the facilities in the EPA's iron and steel sector significantly interfere with ozone attainment in downwind states.

7. EPA's stated basis for cost-effectiveness is RACT, but EPA applied beyond-RACT and beyond-BACT/LAER levels of control to establish emission limits for the steel industry, without any justification of its deviation from RACT. It is illogical on how EPA is now attempting to impose limits that are akin to RACT limits that are more stringent than BACT and LAER limits. A review of the RBLC does not support EPA's proposed limits and technologies.

8. EPA's reliance upon the Menu of Control Measures (MCM) and the Control Strategies Tool (CoST) to identify cost-effective emissions control options for the steel industry is fundamentally flawed, as the underlying studies that EPA used to identify cost-effectiveness did not include numerous U. S. Steel source types where EPA proposes controls in the rule, and EPA chose cost-effectiveness values at the bottom of the study cost ranges despite statements in the underlying studies regarding the screening level approach and likely under-estimating costs.

9. Underlying studies only estimated NOX control costs for reheat and annealing furnaces

10. EPA improperly assigned cost data based on reheat and annealing furnaces to all steel process units in the proposed rule

11. There is no basis in EPA's inclusion of numerous other steel unit types for regulation based on CoST and MCM, when CoST and MCM only have input data for annealing and reheat furnaces

12. EPA's cost estimates inaccurately assume year-round operation of control devices resulting in underestimating cost-effectiveness because the regulation can only apply to the five month ozone season, meaning EPA's cost estimates were only 5/12 or 42% of the real cost effectiveness – This critical error significantly underestimates the cost effectiveness of the proposed controls (even if such controls were found to be technologically feasible)

13. Nothing in the docket supports a finding that any of the proposed reductions (individually or collectively) would have any measurable impacts in downwind states.

14. The lack of a trading option puts non-EGUs at a significant disadvantage when compared to EGUs, is illogical and makes EPA's errors in setting unit-specific emission limits even more critical to the extent many errors result in fatally flawed rule. In addition, EPA has not proposed a case-by-case option for emission units that would be subject to the regulation, whereas almost every prior RACT rule has recognized that emissions and technologies are not fungible and such determination are many times best determined on a case-by-case basis when the general technology and/or limit is shown to be inappropriate or infeasible.

XXI. Due to the Lack of Stakeholder Engagement EPA Fails to Understand the Integrated Steel Making Process.

The Bureau of Industry and Security and Department of Commerce have determined that domestic steelmaking is necessary for our nation's security production requirements and without domestic steel production we run the risk of not being able to adequately respond to a national emergency. In addition, the U.S. Department of Homeland Security has designated steelmakers like U. S. Steel, to be a vital component of our nation's critical manufacturing sector, which is necessary for the economic prosperity, security, and continuity of the United States. The COVID-19 pandemic and the Russian-Ukrainian conflict have highlighted the importance of having robust domestic manufacturing capabilities to supply important products that are essential to national, economic and health security. Therefore, it is imperative that any rulemakings that have the potential to significantly impact the steel industry are accurate and well-grounded in the law and technology. Unfortunately, EPA's Proposed Rule short of these critical criteria.

U. S. Steel has been a critical partner with Federal, State and local governments for over 120 years. Today U. S. Steel employs our "Best For All" strategy where we are diversifying our capabilities and technology through a balance of Integrated Iron and Steel Facilities with scrap to steel facilities using Electric Arc Furnace (EAF) technology. This strategy is critical for U. S. Steel to work towards more sustainable steel production.

In developing the Proposed Rule, EPA did not reach out to U. S. Steel or, to our knowledge, any steel sector stakeholders. This lack of outreach has led to EPA proposing a rule that is illogical and infeasible. In order to truly have a Proposed Rule with positive impacts would require EPA to have a least a minimal understanding of the non-EGU sectors they seek to regulate.

For all of the non-EGU sectors targeted in the Proposed Rule, EPA generically grouped all facilities by the assigned NAICS codes without any attention to the details of the actual facilities, and emission units to be regulated. As discussed within our comments, EPA did not develop emission limits in the Proposed Rule for the emission units to be regulated, but instead attempted to apply a one sizes fits all approach to NAICS code groups like iron and steel facilities. For example, EPA makes assumptions that all reheat furnaces have similar feasibility for emission control technology and the same emission rates even though there are vast differences among the technology and type of reheat furnaces across the iron and steel industry with different emission profiles and emissions

EPA has not clearly explained its screening process in assessing the iron and steel industry. More details are needed for the industry to be able to comment accordingly. For example, in the Proposed Rule, EPA claims that sources with *actual emissions greater than 100 TPY* were assessed, *except well-controlled sources*. However, after reviewing the purported supporting documentation from the docket, it is not clear on what criteria U.S. EPA used to determine if a source was *well-controlled*, and what sources it considered were indeed well-controlled. In addition, EPA states that the rule would apply to any *emission unit* that directly emits or has the *potential to emit* 100 tons per year or more of NOx (and to each BOF Shop containing two or more such units that collectively emit or have the potential to emit 100 tons or more per year or more of NOx. There is a significant difference between actual emissions of over 100 tons and PTE of over 100 tons. In addition, it also appears that a number of emissions units less than 100 TPY actual emissions would inexplicably be covered in the iron and steel category of the Proposed Rule. It is not clear on how or why EPA would include many of the emission units in this category to be subject to FIP limits.

In addition, it is unclear on how BOP Shops are to aggregate emission units; and why and how EPA believes SCR on many of the smaller emission units within a BOP Shop would be appropriate and feasible. For example, BOP Shops generally have a few or several ladle/tundish preheaters. These preheaters are small sources of NOx and NOx controls on these units – even if assumed to be technologically feasible (which it is not)– would not be economically feasible.

XXII. EPA Failed to Determine Technological Feasibility Related to Integrated Iron and Steel Process.

As explained herein when applying RACT, EPA must demonstrate that the proposed limits are both technically and economically feasible on a facility and unit specific basis. And even stricter standards like BACT still require an analysis of technical and economic feasibility. And in any case, EPA has an independent "duty to examine [and justify] key assumptions as part of its affirmative 'burden of promulgating and explaining a non-arbitrary, non-capricious rule. . . .'"[272]

[272] *Appalachian Power Co. v. EPA*, 328 U.S. App. D.C. 379, 135 F.3d 791, 818 (1998).

and EPA may not "promulgate rules on the basis of inadequate data, or on data that, to a critical degree, is known only to the agency."[273] And thus EPA's assumptions regarding feasibility in the Proposed Rule must be adequately justified. EPA has failed to meet its legal burden as it related to the emission limits in the Proposed Rule related to emission units at integrated iron and steel operations.

A. General Issues with the Application of the Proposed Rule to Integrated Iron and Steel Operations.

The Proposed Rule makes erroneous assumption and contains errors that result in fatal issues with its application to the iron and steel industry. The application of the Proposed Rule will require significant operational changes, excessive costs and, in many cases, minimal NOx reductions and actually increases other air pollutants. The SCR technology in the Proposed Rule is not feasible for the sources/emission units in the iron and steel sector that EPA proposes to regulate. Notwithstanding the fact that EPA has not shown if or how iron and steel facilities are contributing to or interfering with ozone attainment in downwind states, even it did, due to the incompatibility of post combustion controls such as SCR/SNCR with many of emission units at integrated iron and steel facilities, EPA's emission limits in the Proposed Rule are not feasible and are therefore unlawful.

EPA has failed to provide support in the Proposed Rule or accompanying technical documents to show that these required emission reductions are actually achievable or, even if they were, how they would result in any measurable improved ozone air quality in downwind states. In many instances equipment and fuels within the steelmaking industry are already low NOx so reductions are not likely to be achieved; and if any further reductions were technologically feasible, they would be cost prohibited as explained in the Trinity Report and the Barr Report. For instance, the Proposed Rule EPA proposes "[f]or a vacuum degasser, NOX is not generated in the process and so NOX control cannot be applied there despite EPA's proposed control. And for an LMF, EPA proposes low NOX burners as a control technology, but there are no burners in an LMF." Again, in its rush to regulate, EPA has proposed a fatally flawed rule that, if promulgated, would lead to illogical, infeasible results at great costs without a required showing of favorable impacts in the downwind states. That being said, U.S. Steel is committed to working with EPA on sound, proven sensible solutions that are technologically and economically feasible and result in measurable ozone improvements in downwind states if, and only if, EPA first demonstrates and shows that the iron and steel industry interferes with ozone attainment in downwind states, which it has not done so in the proposed rule or its purported supporting documents.

Some of the emission units and US Steel's integrated steel facilities to which EPA would have the SCR emission control applied would require significant preconditioning and heating of the exhaust gas to make it amenable to SCR. The conditioning and heating of exhaust gas prior to being able to utilize a SCR would not only be difficult to design and operate but would also require increased use of natural gas and have other impacts and costs not considered by EPA. The

[273] *Portland Cement Ass'n v. Ruckelshaus*, 158 U.S. App. D.C. 308, 486 F.2d 375, 391-93 (1973).

increased combustion of natural gas that would be required to condition the exhaust gas for a SCR would increase various emissions such as CO2, PM, SO2 and even NOx. The increase in NOx clearly goes against the purpose of the Proposed Rule. Nor did EPA consider the design and infrastructure that would be needed for the conditioning and preheating or the environmental impacts associated with the increases in emissions associated with conditioning and preheating. These issues were overlooked or not recognized by EPA during the development of the Proposed Rule.

EPA also failed to fully and accurately develop the costs that would be incurred by the iron and steel industry. The EPA claims that the SCR technology and the limits set in the Proposed Rule would be cost effective but to arrive at that calculation the costs were estimated if technology ran year-round and not just during ozone season (for. Trinity Consultants provides the following information related to their review of the costs associated:

> "For instance, EPA estimates that selection of SCR in the Iron and Steel Mills and Ferroalloy Manufacturing Industry may be associated with 948 ozone season NOx reductions, at an annual cost of $9,886,092. If EPA had calculated the cost per ozone season ton of NOx reduced, this would result in an estimate of $10,428 per ton of NOx reduced, which is well above the cost threshold of $7,500 stated by EPA). But EPA instead, without justification, lists the average cost per ton as $4,345, which would only be the case if the ozone season tons were extrapolated to assume continuous annual reductions."

In the Proposed Rule, EPA started from a limit that was the lowest emission rates identified in any prior RACT or BACT analysis and inexplicable applied additional controls that would lead to arbitrary and unsustainable additional reductions. These reductions were based on control technologies never before applied to these emission units and only based on incorrect generic assumptions. EPA uses similar approaches for the proposed emission limits for all steel units in proposing emission limits far below those determined as either BACT or RACT in unit-specific analyses. This all further supports that EPA used a flawed methodology in the development of the Proposed Rule. We further note that it is illogical and inappropriate for EPA to now require an unjustified, unproven (and infeasible) limit that is significantly lower than BACT or LAER.

B. Application of the Proposed Rule to Specific Integrated Iron and Steel Operations.

The application of the Proposed Rule to various equipment within an integrated iron and steel facility causes many similar issues. This section will address what some of the concerns are with each part of the operations. The issues with the application to the integrated facility are discussed throughout these comments. The emission units discussed below are also discussed in more detail in the Trinity Report found at Exhibit D.

1. Blast Furnace Operations.

The blast furnace converts iron oxide into molten iron for subsequent refining in the BOPF shop to produce steel. A typical burden (feed) may consist of iron ore, pellets, sinter, limestone, coke, mill scale, BOPF slag, and other iron bearing materials. The burden material is charged into the top of the furnace and slowly descends through the furnace. The coke provides the thermal energy required for the process and provides carbon to reduce the iron oxide and to remove oxygen in the form of CO. To U. S. Steel's knowledge, SCRs are not installed on any blast furnaces domestically or internationally, and in the TSD and docket materials, EPA does not cite to any successful application of SCR at any blast furnace ("BF"). This is because SCRs are not technologically feasible as a NOx control for blast furnaces; nor are they cost-effective. U. S. Steel conducted a BART analysis of the BF at Gary Works in 2020 and a RACT analysis at the Edgar Thompson facility in 2014 both of those evaluations indicated the Proposed Rule is not feasible. These are both discussed further in the Trinity comments found in Exhibit D.

BFs use blast furnace gas, coke oven gas, or other heat sources to generate the heat necessary to metal the iron. The use of regenerative heat capitalized on the blast furnace gas ("BFG"). BRG is a low NOx gas and already uses a best practices approach and minimizes the impact on air emission. Any excess BFG is flared to minimize air impacts. EPA seems to fail to realize that the SCR technology is not compatible with a BFG gas flare. If BFG was not used to heat the BF then it would require increased use of natural gas, which would have a negative impact on air emissions.

The application of the Proposed Rule to BFs and the limits established were incorrectly achieved. As stated in Exhibit D, prepared by Trinity Consultants:

> "For blast furnaces, EPA started with an Ohio RACT limitation and then assumed a 50% reduction (from that RACT limitation) based on application of a control technology never before applied to this source type. EPA uses similar approaches for the proposed emission limits for all steel units in proposing emission limits far below those determined as either BACT or RACT in unit-specific analyses. EPA appears to base its approach on an incorrect interpretation of the data in MCM and CoST and does not include any fact-based finding that these technologies are applicable to the steel emission units as part of this proposal."

Emission limits should be set following the application of appropriate regulatory requirements, accurate information, with appropriate control technologies. It appears that none of this was done with the development of the emission limits for the Proposed Rule.

2. Basic Oxygen Process.

Basic Oxygen Process (BOP) is treated differently than all other non-EGU sources. In the other various non-EGU sources there is potential to emit of 100 tpy of NOx as individual emission units to be included in the Proposed Rule. However, BOP operations are required to combine all emission units in determining whether the emission limits in the Proposed rule apply to the emission units at the BOP operations. This combining of emission units results in the application of SCR requirements to potentially very small emission units that do not have an associated stack. Requiring SCR emission controls on units that emit very few tons of NOx per year is overly burdensome, costly and will have no impact on downwind states. The result is illogical.

The BOP is not conducive to the application of the Proposed Rule's SCR technology to decrease NOx emissions. BOPs typically operate with a wet scrubber exhaust system which produces a gas too cool to go into a SCR/SNCR without significant conditioning and heating. Even assuming there is sufficient space, the BOP exhaust system would have to be a completely new design likely to include larger fans and increased duct work. The gas would also have to be heated to temperatures compatible with the SCR resulting in significant, independent NOx emissions. Both of these equipment additions would lead to increased natural gas and electricity usage.

EPA did not consider the costs for redesign of the BOP systems (nor should it as such redesign goes beyond RACT), modification of equipment and process to attempt to work with the SCR requirement, additional equipment needed, additional natural gas, or additional electricity costs. In the EPA's limited understanding of the iron and steel process they also failed to realize that imposing the SCR technology will also lead to emission increases associated with the increased usage of natural gas and electricity. Nothing in the rulemaking docket indicates that EPA considered these costs and impacts; and how the (incorrectly) assumed reductions benefit downwind states.

It is significant to note that EPA has not shown how SCR has been applied on any BOP Shop; and that the anticipated reductions are indeed achievable – technologically and economically. In the TSD, EPA states that it based the emission limit of 0.07 lb/ton of steel on performance testing data from basic oxygen furnaces without NOx reduction controls at integrated iron and steel mills in the United States. EPA then projected what it refers to as a minimal 50% NOx reduction efficiency that EPA, without any support whatsoever, is achievable by use of low-NOx technology, including potential use of FGR and selective catalytic reduction." EPA's rather simplistic approach is that because most BOF vessels and associated BOF Shops in the United States are already equipped with capture technology and existing particulate matter control devices, the NOx reduction technology could simply be integrated to the existing controls. This over-simplification is not supported by fact or law. EPA has not shown that SCR has been successfully applied to BOP Shops. The dynamic conditions in the exhaust gases, including dramatic swings in flow and temperature (e.g., oxygen blow vs. charging or tapping) make SCR inappropriate – and this is supported by the fact that EPA and states/air agencies have never applied SCR to the basic oxygen furnace process shops for any RACT, BACT or LAER determination. However, with the broad stroke in one simple paragraph, EPA, without any support, upends decades of prior determinations, and now inexplicably claims SCR is somehow feasible and appropriate. The TSD is scant on any support – but instead EPA relies on false assumptions.

3. Ladle Metallurgy Furnace.

Ladle metallurgical furnaces (LMF) are used in the steel industry to increase the liquid metal temperature for casting and to produce steel grades by adding alloys. The LMF process is a batch process and since there is no combustion source (except for de minimis amounts associated with the consumption of electrodes by oxidation with oxygen in capture air) there is minimal NOx emissions. In sum, applying SCR at an LMF is inappropriate and illogical. In addition, the application of SCR is not technically feasible, in part due to the batch process of the LMF. Even if one were able to determine how to implement the SCR on a LMF, it would not be cost-effective as it would require an entire redesign of the system and process with de minimis reductions in NOx. Furthermore, because EPA includes LMF as part of the BOP Shop, there is no de minimis threshold for the applicability of the FIP to LMFs (assuming that the BOP Shop's PTE (from all units within the shop) is 100 tons or more. This is illogical – so illogical that the cost effectiveness would be approach $2 million per ton of NOx removed – several orders of magnitude of EPA's purported cost threshold of $7,500/ton. Furthermore, EPA has not shown how LMFs (individually or aggregately with other emission units) interfere with ozone attainment in downwind states; nor has EPA shown how the emission limits for LMFs would lead to any measurable benefits in ozone in downwind states.

4. Degassers.

EPA appears to have a fundamental misunderstanding of vacuum degassing and NOx emissions (de minimis) associated with the process. Vacuum degassers (VDGs) are used in the steel industry to remove certain gases from the molten steel prior to casting. This helps to produce the desired properties of the finished steel. Degassers can remove hydrogen (H_2), oxygen (O_2), and nitrogen (N_2) that are dissolved in the liquid metal. They are also used to reduce the carbon content of the steel prior to casting to produce an ultra-low carbon product.

While not clear from Proposed Rule, it would appear that EPA would intend to include vacuum degassing in the BOF Shop, and therefore, not subject to the triggering 100 ton PTE threshold, and, instead, would inexplicably be included and subject to the proposed limits even if no appreciable reduction would result. The process of the degasser itself does not generate NOx – and therefore its inclusion in the proposed rule is perplexing. The only NOx associated with vacuum degassing is NOx generated by the flare when CO abatement and is a function of adiabatic flame temperature which is related to excess air, fuel usage and flare design. EPA's has scant support for its inclusion of vacuum degassing and the proposed limit of 0.03 lb/mmbtu on existing permit limits of 0.05 lb/mmbtu. (EPA's entire technical support discussion in the non-EGU TSD for the limit is provided below:

> "For vacuum degassers utilized in secondary steelmaking, EPA based the limit of 0.03 lb/mmBtu on existing permit limits of 0.05 lb/mmBtu. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including use of selective catalytic reduction."

EPA does not provide any further explanation – and a review of the RBLC does not support EPA's ambiguous and vague conclusions.

Installing emission control technology on VDGs is not feasible. VDGs are a batch process and has variables in the exhaust gas. Again, due to the de minimis amounts of NOx peripherally associated with vacuum degasser flares and the low potential reduction of NOx from installation of SCR technology (even if it were feasible, which it is not) results in a technologically infeasible limit that is not cost-effective. VDGs also are very low in NOx emissions and do not meet the 100 ton per year threshold in the Proposed Rule. However, the VGDs are inexplicably pulled into the aggregated numbers of the BOP or BOF emissions

5. Ladle/Tundish Preheaters.

Ladle or Tundish preheaters are small natural gas burners that direct fire ladles to keep them warm, dry or preheat them – as an ancillary process and to better preserve refractory. The preheaters are used to dry out ladles and there is no vent or combustion exhaust gas capture. In this case SCR technology is not feasible as there is nothing to add the SCR to at the end of the exhaust. EPA failed to understand the use of these preheaters and did not make any determination as the feasibility of putting SCR on the ladle or tundish preheaters. If the Proposed Rule is finalized there would be significant costs in trying to absolutely redesign these preheaters to accommodate the possibility of SCR.

Ladle preheaters are such a small potential source of NOx that there will be no impact from this change on downwind states. Most states already consider this to be an insignificant activity for air emissions and consider it fugitive emissions.

The gas burners on the preheaters are very small with heat inputs of typically 5-15 MMBtu/hr. In addition, the preheaters are needed to be mobile so that they can be use don ladles throughout the shop. The very small heating value, coupled with the de minimis NOx emissions from ladle preheating, and the inconsistent and mobile operation makes SCR technologically infeasible. And even if SCR were technologically feasible, which it is not, it would not be economically feasible, as even if the emissions from the units were able to be captured in a hood and treated, the cost estimate of nearly $50,000/ton of NOx removed, not including any costs associated with hooding and other infrastructure needed to accommodate the technology. Simply, the proposed limit based upon application of SCR is perplexing.

The ladle preheaters are very low in emissions and do not meet the 100 ton per year threshold in the Proposed Rule. However, the preheaters are inexplicably pulled into the aggregated numbers of the BOP or BOF emissions. Any potential reduction from ladle or tundish preheaters would be minimal and would not be cost-effective. Furthermore, EPA has not shown how the insignificant NOx emissions from ladle/tundish preheaters interfere with ozone attainment in downwind states; or how downwind states would have any measurable benefit from the proposed limits. Again, there appears to be a fundamental misunderstanding of the industry and the limitations of the proposed SCR technology to these sources.

6. Hot Strip Mill Operations/Reheat Furnaces.

Hot Strip Mills are specifically designed operations, and any addition of equipment or technology requires significant planning, engineering, time, and money. EPA's failure to understand the complicated operations at a hot strip mill has led to the Proposed Rule significantly underestimating the difficulty that would be involved in retrofitting the prescribed emissions control equipment in the Proposed Rule. The cost and ability to retrofit equipment within a hot strip mill is going to be extremely difficult and require significant modification to operations. A retrofit of this nature will also cause significant downtime and associated loss of revenue. The proposed SCR technology if it is even capable of being installed will require extensive modification to accommodate the changes.

The U. S. Steel Gary Works facility as well as other facilities have completed a RACT analysis for hot strip mill operations related to Regional Haze. Operations at these facilities have already been modified to meet the RACT requirements. The Proposed Rule attempts to regulate beyond the requirements already in place, through what can only be characterized as a "beyond-LAER" emission limit. LEAR. All of the changes (for all integrated iron and steel operations) in the Proposed Rule will have a minimal impact on attainment in downwind states. Continuing to push for unproven and very costly technology to be applied with little to no appreciable improvement is not the purpose of this section of the CAA.

Reheat furnaces are used to reheat slabs of steel to work and shape the steel into another product. The reheat furnaces use uniform heat and hold the desired temperature for a set time. The design and operation of reheat furnaces makes SCR technology infeasible.

The U. S. Steel Irvin Works evaluated RACT for a reheat furnace in 2014. Trinity Provides an overview in Exhibit D. However as expected "That analysis found that the cost of adding low NO_X burners would be $14,100/ton, which is not cost effective." The U. S. Steel Gary Works facility then conducted a BART analysis for reheat furnaces in 2020. The BART analysis found that the cost of adding low NO_X burners would be $14,100/ton, which is not cost effective under the purported cost threshold of $7,500 that EPA arbitrarily set forth iron and steel units in the Proposed Rule. Due to the heat needed these burners would likely increase the energy use as well. Creating another expense and likely increasing air emissions.

Again, EPA fails to understand the iron and steel industry and does not show that the Proposed Rule meets its purpose to improve air emissions related to NOx.

7. Annealing Furnaces.

Annealing furnaces go through a series of heating and cooling process allowing hard metals to have various ductility and strength. Annealing furnaces are designed to operate in a batch or continuous function. Continuous Annealing furnaces are the only steelmaking equipment that has been shown to be feasible with the SCR technology. However, SCR is not feasible on batch annealing furnaces.

While the SCR technology may be technologically feasible for continuous annealing furnaces it is not cost effective. Trinity Consultants performed a "control cost effectiveness analysis on the Irvin open coil annealing furnace, which showed that the SCR cost effectiveness would be at best $25,630 (2021$). This is well beyond the EPA stated $7,500.

EPA also did not use the proper methodology to set emission limits for the annealing furnaces. There is additional technical information in the document prepared by Trinity Consultants which states "for annealing furnaces, EPA started with recent BACT determinations, and then applied an additional 40% reduction without any demonstration of achievability of the proposed limit." These numbers are not based upon proper determinations and EPA did not provide support for the additional 40% reduction found in the Proposed Rule.

8. Boilers

Boilers used at integrated iron and steel facilities vary greatly as will the NOx emission rates. These boilers will also have a variety of fuel sources and operating parameters. Each boiler would have to be evaluated as to the potential to reduce NOx emissions, the technical feasibility of SCR and the cost effectiveness.

U. S. Steel conducted a BART analysis on the Clairton facility boilers in 2022. That analysis showed the SCR annual cost effectiveness was at minimum $20,873/ton on Boiler 2, and more expensive on others. Additional review has been done at other U. S. Steel facilities and that information is provided in the Trinity Report in Exhibit D.

Some of the boilers already combust BFG which is low NOx and considered a best practice. This is significantly better from an environmental perspective than an alternative like natural gas that would displace the BFG and increase air emissions. Any modification of boilers would require significant modification to attempt to accommodate SCR. This would not only be costly but would likely produce negative air impacts, especially if boilers were switched to natural gas.

Boilers are yet another area where EPA need to evaluate in more detail, likely through a separate rulemaking or individual RACT determinations, in order to justify the emission limits, it purports to apply "wholesale" to boilers in the Proposed Rule.

SPECIFIC COMMENTS PERTAINING TO MINNESOTA MINING OPERATIONS

XXIII. Minnesota Should Not be Regulated in the Proposed Rule.

Minnesota is not having a significant impact on downwind air quality. Minnesota was identified as a non-significant contributor (below 0.7 parts per billion) to any ozone monitors in the 2018 modeling performed by both EPA and LADCO. Minnesota's original submittal should have been approved based on contribution information available from both EPA and LADCO at that time.

While EPA now maintains that, with new modeling, it has found contributions in excess of 0.71 ppb at two monitors, EPA's position that this alone is sufficient to subject Minnesota to regulation is based on an overly-conservative assumption that a 1% threshold is sufficient to justify regulation of downwind ozone impacts.

Breaking out the sources of the receptor impacts EPA modeled shows that the regulated emissions from Minnesota are having less than a 0.3 ppb impact on down-wind monitors.

2026 MN-Specific Scenario	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Illinois (001) Results (ppb)	72.5	0.91	0.19	0.04

Illinois (076) Results (ppb)	71.3	0.75	0.18	0.03

In other words, eliminating all non-EGU and EGU emissions from Minnesota would not affect Illinois' attainment status.

If the sources being evaluated for controls are not providing a reduction that would have any appreciable impact on attainment or maintenance of the NAAQS, then EPA cannot support regulating those emissions as "amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard." 42 U.S.C. § 7410(a)(2)(D)(i)(I); *see also EPA v. EME Homer City Generation, LP*, 134 S. Ct. 1584 (2014) ("EPA cannot require a State to reduce its output of pollution by more than is necessary to achieve attainment in every downwind State or at odds with the one-percent threshold the Agency has set. If EPA requires an up-wind State to reduce emissions by more than the amount necessary to achieve attainment in every downwind State to which it is linked, the Agency will have overstepped its authority, under the Good Neighbor Provision, to eliminate those "amounts [that] contribute ... to nonattainment.").

Simplified assumptions are sometimes appropriate and necessary in a complex modeling analysis such as a national photochemical ozone evaluation. However, when the results are used to justify costly controls and monitoring on a significant number of industrial operations in the state, further culpability refinements need to be assessed. Arbitrarily requiring controls across multiple non-EGU facilities in a state contributing more than 0.71 ppb to a modeled ozone value greater than 70 ppb demands an extra step confirming that the specific non-EGU sources EPA seeks to regulate are in fact significant contributors from each state.[274] Again, looking at the impacts modeled for the State of Minnesota, the maximum modeled impact is less than 1 ppb.

MN	Keetac, Minntac	Cook (1), IL: 73.4 Cook (76), IL: 72.1	Cook (1), IL: 0.97 Cook (76), IL: 0.79	Cook (1), IL: 72.5 Cook (76), IL: 71.3	Cook (1), IL: 0.91 Cook (76), IL: 0.75

As discussed in the above Section VI. G titled "Improper Significance Screening Threshold," no impact below 1 ppb can be considered significant, due to EPA's 2018 guidance finding that a 1 ppb threshold is generally comparable to a 1% threshold for the 2015 ozone NAAQS in terms of the contributions it would cover, 1 ppb being the lowest significant digit used for reporting ozone monitoring data under the NAAQS, and EPA previously determining based on statistical analysis underlying the Ozone SIL that no contribution below 1 ppb can have a

[274] In fact, as discussed previously, there is no statutory justification for EPA to group unrelated industries together as a lump title of "non-EGU" sources for purposes of evaluating the significance of impacts, and it is arbitrary to lump all such industries together when EPA provides industry specific consideration to the EGU industry. EPA must evaluate the significance of the particular sources is seeks to subject to the rule if it wishes to impose facility or unit specific emission controls. If on the other hand EPA wishes to create an emissions trading regime similar to that currently in place for EGUs, EPA must at minimum demonstrate that any industries included in such trading regimes are significant contributors to each specific state's linked receptors.

significant impact on a downwind receptor. Based on this limited impact at even the maximum modeled influence on receptors, EPA's argument that Minnesota emissions need to be controlled for future ozone NAAQS demonstration based on a maximum contribution of between 0.75 and 0.97 ppb is not justifiable.

EPA's decision to regulate Minnesota based on a maximum modeled contribution of 0.97 ppb rather than EPA's guidance threshold of 1 ppb also is particularly troubling because the model EPA is using lacks the consistency and accuracy needed to make such fine-grained distinctions. Rather, based on EPA's own assessment in the modeling TSD, "the regional mean bias of the model is +/- 5 ppb and the mean error is between 6 and 7 ppb on average for all days during the period May through September in each region."[275]

	Model/Obs. (ppb)	Mean Bias (ppb)	Mean Error (ppb)	Standard Deviation (ppb)
Cook County, IL (001)	60.75/68.97	-8.22	11.13	8.16
Cook County, IL (076)	57.87/67.77	-9.90	11.85	8.65

These numbers challenge the assumption in the Proposed Rule that emissions from Minnesota are "significant." It is simply insupportable to assert that unprecedented and costly emission reductions are needed to achieve an impact on down-wind monitors that is less than the error in EPA's model.

XXIV. Taconite Should Not be Regulated in the Proposed Rule.

Taconite is not part of the Iron and Steel and Ferroalloy Manufacturing Industry Group. EPA's modeling analysis of contributions from non-EGU emission units was conducted on an industry-group basis, based on 4-digit NAICS codes.[276]

EPA created two "tiers" of industry groups. *Id.* The first tier includes four industries that EPA proposes it "should focus the assessment of NOx reduction potential and cost primarily on": pipeline transportation of natural gas; cement and concrete product manufacturing; iron and steel mills and ferroalloy manufacturing; and glass and glass product manufacturing. *Id.* The preamble to the Proposed Rule appears to include "Taconite production kilns" as a source in the Iron and Steel and Ferroalloys Manufacturing Industry Group.[277] Further, the proposed language of 40 CFR § 52.43, which applies to Iron and Steel Mills and Ferroalloy Manufacturing is proposed to include in the definition of "Affected unit" "taconite production kiln."[278]

[275] Air Quality Modeling Technical Support Document, EPA-HQ-OAR-2021-0668-0099 at A-7.

[276] 87 Fed. Reg. at 20,083; see also EPA-HQ-OAR-2021-0665-0191, at 1.

[277] 87 Fed. Reg. 20,046, Table IV.B-4; *id.* at 20,145, Table VII.C-3.

[278] 87 Fed. Reg. at 20,181.

To the extent EPA is including taconite kilns in the Proposed Rule because they are part of "iron and steel mills and ferroalloy manufacturing," this is incorrect. Taconite production is not part of iron and steel or ferroalloy manufacturing. The modeling underlying the Proposed Rule categorizes emission units based on the NAICS Code of the subject facilities. The NAICS code for iron and steel manufacturing is 3311. Metal ore mining, including taconite production, has NAICS code 2122. This is documented in EPA's own modeling data from September 29, 2021. Section 2.5.2 of the RIA describes the industry EPA intended to regulate in the Iron and Steel Mills and Ferroalloy Manufacturing NAICS code:

> Iron is produced from iron ore, and steel is produced by progressively removing impurities from iron ore or ferrous scrap. ***The first step is iron making.*** Primary inputs to the iron making process are iron ore or other sources of iron, coke or coal, and flux.

(emphasis added). This description does not include mining or processing of taconite prior to the iron making process.

It is arbitrary to include taconite kilns in the Proposed Rule because EPA has not modeled the significance of their contribution to any downwind receptor as would be required. Taconite production is not separately mentioned in the Non-EGU Screening Assessment which is EPA's sole basis for determining which industries had a significant enough impact relative to subject to the Proposed Rule. EPA states that that modeling was done on the basis of NAICS code, which would mean that taconite kilns were not included in the modeling of the contributions from the Iron Steel and Ferroalloy industry since as noted above taconite production belongs to a different NAICS code. This is confirmed by the fact that there appear to be no taconite kilns listed in the list of facilities and emission units evaluated as part of the Non-EGU Screening Assessment.[279] Because taconite production was never modeled to be a significant contributor to downwind nonattainment or maintenance issues, it cannot be regulated under the Good Neighbor provision of the CAA. Furthermore, there is no rational basis to treat Taconite as part of the Iron and Steel and Ferroalloy Manufacturing Industry Group. Taconite production is not co-located with iron and steel manufacturing. As a result, there are no taconite production kilns "at an iron and steel mill or ferroalloy manufacturing facility."[280] Taconite production does not use similar processes, have similar emission profiles, or use similar pollution controls. There is no factual basis to conclude that taconite production and iron and steel manufacturing have similar impacts on downwind receptors, similar costs of pollution controls, or should otherwise be grouped together for purposes of screening or regulation under the Proposed Rule.

XXV. Taconite Was Properly Eliminated from EPA's Screening Assessment as a Tier 2 Source Without Significant Boiler Emissions.

[279] Non-EGU Screening Assessment at Table 6; see also excel file in regulatory docket titled "Screening Assessment Non-EGU Facility and Emission Unit Limits List".

[280] *Id.*

While there is no rational basis to include taconite kilns in the Iron and Steel and Ferroalloy Manufacturing Industry Group, EPA did evaluate the Taconite Industry as part of the Metal Ore Mining Industry Group in its Screening Analysis. In doing so, Taconite was appropriate *excluded* from the Proposed Rule.

Specifically, in the "Non-EGU Screening Assessment," the Metal Ore Mining Industry (4-digit NAICS 2122) was originally included as a Tier 2 industry group; however, in a later step in the analysis EPA refined the Tier 2 grouping by identifying potentially impactful industrial, commercial, and institutional ("ICI") boilers, using the projected 2023 emissions inventory in the linked upwind states. This eliminated the Metal Ore Mining Industry Group from the assessment entirely, as EPA found that it had no "potentially impactful" boilers.[281]

Based on EPA's own assessment, therefore, boilers in the Metal Ore Mining industry, which would include the Taconite Industry, do not provide opportunities for NOx emissions reductions that result in meaningful impacts on air quality at downwind receptors.

XXVI. There is No Other Support in the Record for Subjecting the Taconite Industry to Regulation.

The record is notably lacking in any analysis that would support including the Taconite Industry, on its own or as part of the Iron and Steel and Ferroalloy Manufacturing Industry.

As EPA explains in the preamble to the Proposed Rule, "for Taconite Production Kilns, the EPA does not currently have the data to determine appropriate emissions limits that these units could achieve by installing low NO_X burners. Therefore, the EPA is proposing to require the installation of low NO_X burners for Taconite Production Kilns and work practice standards for operating these control technologies to achieve emissions reductions. The EPA is also proposing to require these sources to perform performance tests and establish a unit-specific emissions limit at that time. These work practice standards are consistent with EPA's Taconite FIP for Minnesota.[282] Due to the ongoing nature of this FIP, the EPA is proposing to require installation of specific control technologies and a period of evaluation before setting a numerical emissions limit."[283] This is just another way of saying EPA does not have sufficient data to impose emission regulations and that this data, and the regulations themselves, will come from the Taconite FIP. If EPA lacks the data to regulate now, the only option is to exclude Taconite from regulation. EPA cannot promulgate a "placeholder" rule that simply says EPA will regulate later.

EPA has also not done any of the assessments for Taconite that have been included to support the Proposed Rule for other sources. The data EPA used for its screening assessment did not include taconite kilns.[284] EPA's Screening Assessment identified 489 emission s units with

[281] Screening Assessment at 5; *see also id.* at 6, Table 1: Number of Emissions Unit Types in Tier 2 Industries in the Non-EGU Screening Assessment.

[282] See 81 FR 21671 (April 12, 2016).

[283] 87 Fed. Reg. at 20,146.

[284] EPA-HQ-OAR-2021-0668-0191 Attachment 1.

greater than 100 tpy of NOx emissions at approximately 250 facilities, none of which were taconite kilns or taconite facilities. EPA's estimates of costs did not look at taconite facilities.

Had EPA looked at the costs of regulating the Taconite Industry, it would have been forced to reject the \$7,500/ton threshold suggested by its modeling. Barr has completed an initial draft cost estimate for a retrofit installation of low-NOx burners on one of the U.S. Steel Minntac's Step III 153 MMBTU/hr Natural Gas-Fired Heating Boilers using the Proposed Rule's NOx emission limit for Natural Gas Fired Boilers of 0.08 lb/MMBTU. The preliminary cost estimate shows that if one of Minntac's Step III 153 MMBTU/hr Heating Boilers was retrofitted with a low-NOx burner, the resulting pollution control cost would be ~\$20,000/ton of NOx removed, which exceeds EPA's cost effectiveness threshold of \$7,500/ton. EPA's benefits calculations (EPA-HQ-OAR-2021-0668-0134) did not look at benefits from regulating taconite kilns. EPA's examination of ongoing compliance costs did not look at taconite facilities.[285] Without the relevant data and a satisfactory explanation for its actions, EPA cannot include the Taconite Industry in regulations that are otherwise completely focused on other sources.

XXVII. Excluding Taconite from the Proposed Rule is Proper Because the Proposed Rule Imposes No Limits on the Industry.

NOx emissions from taconite kilns are already regulated by detailed regional haze FIPs covering Minnesota and Michigan.[286] This FIP imposes stringent NOx emission limits based on the installation of low-NOx main burner systems as the best available retrofit technology ("BART"), with specific emission limits and implementation schedules established for each taconite facility based on its own historic performance and retrofit capabilities. Minnesota has noted in prior comments that the Taconite FIP is already responsible for just under 11,000 tons per year in NOx reductions in the State, including 5,700 tons per year from U. S. Steel's Keetac and Minntac facilities.[287] This is a demonstration of the considerable environmental improvements that have already been achieved in Minnesota air quality and interstate transport of NOx from Minnesota. The Proposed Rule recognizes the effectiveness of the Taconite FIP, pointing to the FIP requirements as the very requirements needed by the Taconite industry "to achieve the required emissions reductions [to satisfy the] remaining interstate transport obligations for the 2015 ozone NAAQS."[288] Even if the Taconite Industry were subject to regulation under EPA's Screening Assessment, this finding would support excluding the Taconite Industry from further regulation, because there are no further restrictions needed to prevent significant contribution to nonattainment or interference in maintenance of the ozone NAAQS, and EPA is not permitted to over-control sources.[289]

[285] Information Collection Request, EPA-HQ-OAR-2021-0194 at 4 and 11-12.

[286] 40 CFR §§ 52.1235 and 52.1183 (the "Taconite FIP").

[287] Minnesota SIP Denial Comments at 2.

[288] 87 Fed. Reg. at 20,045.

[289] *EPA v. EME Homer City Generation, LP*, 572 U.S. 489 (2014).

Minnesota has itself urged EPA to "have these significant reductions included in the 2016v2 inventory for non-EGUs" rather than take credit for them in the new FIP.[290] But EPA does not draw the right conclusion from the results of the Taconite FIP. No other non-EGU is subject to this type of double-regulation in the Proposed Rule, and EPA provides no justification for singling out taconite kilns in the Proposed Rule. As with other industries that are not Tier 1 sources and do not have large boilers subject to Tier 2, the Taconite Industry should be excluded from the Proposed Rule.

XXVIII. The Proposed Rule Should Not Incorporate Another FIP by Reference.

As discussed above, the Taconite Industry is already subject to stringent NOx regulations by the Taconite FIP. EPA proposes to re-impose these same requirements in the Proposed Rule, essentially double-counting reductions that have already been mandated by the State of Minnesota and EPA. Specifically, the Proposed Rule nominally includes taconite kilns, erroneously categorized as part of the Iron and Steel and Ferroalloy Manufacturing Industry, but the emission limits in the Proposed Rule for taconite kilns are "Work practice standard[s] to install low NOx technology/burners, test and set."[291] This requirement is explained as being imposed because it is "[c]onsistent with requirements in Minnesota Taconite FIP *See* 81 FR 21671."[292] The proposed rule language is even more explicit, stating that Taconite Production Kilns are to "Install and operate low NOX burners as required by 2013 and 2016 Minnesota FIPs. 40 CFR § 52.1183." 87 Fed. Reg. at 20,181, Table 1 to Paragraph (c).[293] In other words, the Proposed Rule does not impose emission limits on the Taconite Industry. It only incorporates requirements from the already-imposed FIP.

Taking a FIP that has already been imposed for regional haze and recasting it in duplicate form as an ozone transport requirement is inefficient and inappropriate. Rather than imposing a redundant Taconite FIP requirement in the Proposed Rule, EPA should find that, considering the Taconite FIP, no further regulation of the Taconite Industry is needed to address.

XXIX. If EPA Ultimately Incorporates the Taconite FIP in the Proposed Rule, it Must Accurately Reflect the Requirements of the Taconite FIP.

Including the Taconite Industry in the Proposed Rule is at best redundant with the Taconite FIP. At worst, the Proposed Rule will conflict with the Taconite FIP it purports to incorporate, creating confused and potentially inconsistent requirements.

In the Taconite FIP, EPA attempted to impose a single uniform emission limit across all taconite kilns. This resulted in over ten years of litigation, which is still ongoing, and multiple

[290] Minnesota SIP Denial Comments at 2.

[291] 87 Fed. Reg. 20,046, Table I.B-4 and 20,145, Table VII.C-3.

[292] *Id.* at Table VII.C-3.

[293] The Proposed Rule's citation is incorrect. 40 CFR § 52.1183 is the Michigan regional haze FIP. The Minnesota FIP is at 40 CFR § 52.1235. This reference also ignores the 2021 Minnesota FIP, which addressed Minntac. See 86 Fed. Reg. 12,106 (March 2, 2021).

revisions to the Taconite FIP to incorporate the unique circumstances of each facility.[294] Additional revisions are anticipated following negotiation of revised language for U. S. Steel's Keetac facility.

In attempting to paraphrase the Taconite FIP in a single line, the Proposed Rule falls into the same error. The Proposed states that taconite kilns will "install, maintain, and continuously operate low-NO_X burners to reduce existing average NO_X emissions from the facility by 40% during all periods of kiln operation."[295] This language is nowhere in the Taconite FIP. Rather, the Taconite FIP sets out a detailed and comprehensive plan for establishing achievable emission limits for a variety of taconite production kilns. Minnesota has itself estimated that reduction from low-NOx burners to range from 2%-65% based on the emission unit.[296]

The language used in the Proposed Rule is also far too vague to serve as a regulatory requirement. The Proposed Rule provides no process for calculating "existing average NO_X emissions from the facility."[297] The Proposed Rule provides no support for its derivation of a 40% NOx reduction at all taconite kilns. As noted above, EPA previously attempted to impose uniform emission limits on all taconite furnaces. The result was ten years of litigation and multiple rounds of rulemaking revisions to arrive at case-by-case, unit specific emission limits for the taconite industry that have been demonstrated achievable based on actual emissions data.

The Proposed Rule does not recognize that Minntac's Taconite FIP requirements were expressly negotiated to be an aggregate emission limit across five kilns, not a single reduction at each kiln.[298] The Proposed Rule improperly directs that a specific technology by used at taconite kilns (low-NOx burners). In both the Taconite FIP and for all other sources in the Proposed Rule, emission limits are set based on available technologies, but each source is free to achieve the limit based on any combination of emission controls. For facilities that have not yet installed low-NOx burners, the Proposed Rule provides for using data from "within five years of the effective date of this rule to be used as baseline emission testing data providing the basis for required emission reductions."[299] This ignores the test-and-set schedules established in the Taconite FIP for many facilities.[300] U. S. Steel and EPA are currently negotiating a revised limit for Keetac that would include its own implementation schedule, which may or may not match that of the Proposed Rule.

The operating, monitoring, and recordkeeping requirements in the Proposed Rule are all drafted on the assumption that there is an applicable emission limit for the regulated unit. Requirements that a facility use CEMS to "monitor compliance with the emissions limits set forth

[294] *See* 81 Fed. Reg. 21,687 (April 12, 2016); 86 Fed. Reg. 12,106 (March 2, 2021).

[295] 87 Fed. Reg. at 20,182.

[296] EPA-R05-OAR-2022-0006-0011-attachment_1.

[297] 87 Fed. Reg. at 20,182.

[298] *See* 40 CFR 52.1235(b)(iii).

[299] 87 Fed. Reg. at 20,182.

[300] *See, e.g.*, 40 CFR 42.1235(b)(ii)(A)(2).

in Table 1 to paragraph (c) of this section," or record 30-day averages "in excess of the applicable NOx emission limit in Table 1 to paragraph (c)" do not make sense if there is no numeric emission limit imposed in Table 1 to paragraph (c).[301] Similarly, the Proposed Rule's requirement that taconite kilns "continuously operate NOx control devices as necessary to achieve emission limits set forth in Table 1 to paragraph (c) of this section" makes no sense in the context of the Taconite FIP.

Finally, the Proposed Rule goes beyond EPA's authority when it requires taconite kiln operators to "continuously operate low-NOx burners to reduce existing average NO_X emissions from the facility by 40% during all periods of kiln operation" in order to prevent contribution or interference with an ozone NAAQS that are justified throughout the rulemaking only for the ozone season.

The Proposed Rule not only needlessly restates requirements that are already reflected in the Taconite FIP, it adds confusion and either undoes, or redoes, without sufficient information or support, evaluations and productive efforts that have occurred for over 10 years and that have resulted in significant NOx reductions that have been shown to be technologically and economically feasible. This is needless overregulation and should be removed from the Proposed Rule.

XXX. Minntac and Keetac Modeling Corrections Are Required

Minntac is modeled to emit 3,900-4,167 tpy from 2032 to 2023. September 29, 2021, Emissions Data. Minntac has already committed, as reflected in its 2013 title V permit, to reduce emissions to 3,990 tpy as an annual cap on all facility NOx emissions.

Keetac is project to emit 4,631-4,949 tpy. According to the 2016 Barr Engineering analysis submitted to EPA, baseline calculations of Keetac data should not be based on recent emissions data because it is not representative of the mix of fuels the Keetac furnace is permitted to burn. Even so, a far more representative baseline is 3,455 tpy for uncontrolled NOx emissions.

SPECIFIC COMMENTS RELATED TO STATE IMPLEMENTATION PLANS

XXXI. The Proposed Rule Does Not Provide Adequate Deference to State Approaches to Regulation of Interstate Transport of NOx, as Required by the Principles of Cooperative Federalism Contained in the Clean Air Act.

State primacy in developing implementation plans and the opportunity to cure perceived defects in implementation plans are two examples of a broader theme of cooperative federalism that runs throughout the Clean Air Act. *See Bell v. Cheswick Generating Station*, 734 F. 3d 188, at 190 (3rd Cir. 2013) (The Clean Air Act "employs a 'cooperative federalism' structure under which the federal government develops baseline standards that the states individually implement and enforce."); *Michigan v. EPA*, 268 F.3d 1075, 1083 (D.C. Cir. 2001) (the Clean Air Act "is an experiment in cooperative federalism"); *see also Am. Trucking Ass'ns v. EPA*, 600 F.3d 624, 625

[301] 87 Fed. Reg. at 20,182.

(D.C. Cir. 2010) (under the Clean Air Act, "both the Federal Government and the States . . . exercise responsibility for maintaining and improving air quality"). As Justice Kennedy stated in dissent in *Alaska DEC v. EPA*:

> If cooperative federalism is to achieve Congress' goal of allowing state governments to be accountable to the democratic process in implementing environmental policies, federal agencies cannot consign States to the ministerial tasks of information gathering and making initial recommendations, while reserving to themselves the authority to make final judgments under the guise of surveillance and oversight.
>
> 540 U.S. 461, 518 (2004) (internal citation omitted).

In proposing the FIP, EPA totally obviated Congress' intentions that the Clean Air Act be implemented across the county in a manner that uses cooperative federalism. Instead, EPA unilaterally rejects the State's approaches to regulating interstate transport of NOx originating within their borders, and would impose EPA's own, unproven and infeasible, preferred approach to fulfil the Clean Air Act ozone transport requirements. In doing so, EPA improperly treated the state SIPs are mere "initial recommendations" over which EPA could impose its own "final judgments under the guise of surveillance and oversight."

No state has proposed the type, scope, or stringency of emission limitations contained in the Proposed Rule. This is particularly notable in the context of the NAAQS, which do not require limitation of any particular industry, emission source, or use of any particular control technology to achieve the interstate transport obligations of CAA § 110. This wholesale rejection not just of the states' findings, but their entire approach to regulating emissions within their borders, particularly when combined with the lack of any opportunity for the states to reasonably comment on the denials of their SIPs and amend them in light of EPA's perceived deficiencies, demonstrates a lack of deference to the fundamental principles of cooperative federalism embodied in the Clean Air Act and further cautions against EPA proceeding with the Proposed Rule.

XXXII. EPA is Exceeding its Statutory Authority by Issuing the FIP while Disregarding Approvable SIPs.

EPA does not have authority to impose a FIP when adequate and approvable SIPs have been submitted to EPA.

Under the Clean Air Act, states are given primacy in developing implementation plans for compliance with the national primary and secondary ambient air quality standards. *See* 42 U.S.C. § 7410; *see also Train v. NRDC*, 412 U.S. 60, 79 (1975) (EPA is "relegated by the [Clean Air] Act to a secondary role in the process of determining and enforcing the specific, source-by-source emission limitations which are necessary if the national standards it has set are to be met."). This includes meeting the interstate transport requirements of "prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I)contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, or (II)interfere with measures required to be included in the applicable implementation plan for any other State under part C to prevent significant deterioration of air quality or to protect visibility." 42 U.S.C. § 7410(a)(2)(D)(i).

Only when the state does not submit a compliant SIP, and the Administrator either "(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under subsection (k)(1)(A), or (B) disapproves a State implementation plan submission in whole or in part," does EPA have authority to promulgate a FIP. 42 U.S.C. § 7410(c); *see also Train*, 412 U.S. at 79 ("Under § 110(a)(2), the Agency *is required* to approve a state plan which provides for the timely attainment and subsequent maintenance of ambient air standards, and which also satisfies that section's other general requirements.") (emphasis added).

Nineteen states, including the states of Arkansas, Illinois, Indiana, Michigan, Minnesota, Ohio, and Pennsylvania, have submitted SIPs that meet the requirements of the Clean Air Act and should be approved. Instead of meeting its statutory obligation to review these previously-submitted SIPs, EPA ignored them for years. Now, subject to a short deadline imposed under a consent decree, EPA proposed wholesale disapprovals of these plans without adequate justification and contrary to the mandate of § 110(a)(2) of the Clean Air Act shortly before proposing the FIP in the Proposed Rule.

EPA has not yet finalized its disapprovals and has given the states no opportunity to correct any deficiencies that EPA purports they contain. While EPA has found that some states have not submitted SIPs, for many states, EPA has only proposed disapproval or is still reviewing the state plans. 87 Fed. Reg. at 20,040 (for certain states, "the EPA has proposed, but has not finalized, actions disapproving good neighbor SIP revisions. And for other states, the EPA has not yet proposed action on their good neighbor SIP submittals, but these submittals are currently under review, and EPA intends to act on these submittals in the coming months"). In doing so, the Proposed Rule improperly supplants states' primary authority and would put EPA's preferred ozone approach over the states' own adequate and approvable implementation plans. This is beyond EPA's authority.

EPA's proposed denial of the SIPs is addressed at length in the comments submitted on EPA's proposed SIP denials, including U. S. Steel's own comments on the proposed denials of the Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin SIPs (EPA-R05-OAR-2022-0006-0017) and the Arkansas SIP (EPA-R06-OAR-2021-0801-0043). These comments are equally relevant to the Proposed Rule, and U. S. Steel incorporates them by reference.

As demonstrated in those comments, EPA's proposed SIP denials are not based on proper grounds. Rather, they are based on:

1. Improperly rejecting state assessments of whether in-state emissions were significantly contributing to or interfering with maintenance of downwind attainment of the ozone NAAQS that were not only well within the State's discretion as primary regulators, but consistent with EPA's own published guidance.

2. Moving the goal posts for regulation by creating new modeling after SIPs were already submitted, creating a standard no state could possibly meet.
3. Erroneously relying on incomplete and inaccurate emissions data.

Correcting these issues will demonstrate that EPA does not have grounds to disapprove the previously-submitted SIPs, including the SIPs or Arkansas, Illinois, Indiana, Michigan, Minnesota, and Ohio, and that the Administrator does not have authority to promulgate the proposed FIP.

XXXIII. EPA Does Not Have the Authority to Mandate Emission Limits by Disapproving Adequate SIPs and Imposing its own FIP.

In *Train v. NRDC*, 412 U.S. 60, 79 (1975), the U.S. Supreme Court made clear that states have the authority under the Clean Air Act to develop the specific emission limitations that will ensure compliance with the NAAQS in the first instance. As the Court later stated in *Union Elec. Co. v. EPA*, "Congress plainly left with the States, so long as the national standards were met, the power to determine which sources would be burdened by regulation and to what extent." 427 U.S. 246, 269 (1976); *see also id.* at 267 (states have "virtually absolute power in allocating emission limitations so long as the national standards are met"). In light of the Supreme Court's holdings, the D.C. Circuit has held that the validity of EPA's own NAAQS program "depends in part on whether the program in effect constitutes an EPA-imposed control measure or emission limitation triggering the *Train-Virginia*[302] federalism bar: in other words, on whether the program constitutes an impermissible source-specific means rather than a permissible end goal." *Michigan v. EPA*, 213 F.3d 663, 687 (D.C. Cir. 2000) (internal alterations omitted).

In denying SIPs that adequately prevented significant contribution to nonattainment and interference with the NAAQS and supplanting these state-level approaches with a FIP that imposes EPA's preferred method of achieving the same goal, EPA's Proposed Rule supplants the states' role as primary decider of "which sources would be burdened by regulation and to what extent." This violates the federalism bar established in *Train* and *Virginia v. EPA*.

XXXIV. EPA Has No Authorization to Promulgate a FIP before Disapproving a SIP.

In the Proposed Rule, EPA has not even allowed time to finish deciding whether to disapprove the many ozone transport SIPs submitted for its review. Instead, EPA is accepting comments almost simultaneously both for disapproval of the SIPs and approval of EPA's proposed FIP. In fact, for some states EPA had not even proposed to disapprove the SIP submission before proposing the FIP. This is unlawful because the relevant statute only permits EPA to "promulgate a Federal implementation plan . . . after the Administrator . . . disapproves a State implementation plan submission."[303]

Contrary to EPA's assertion, no court decision has ever authorized EPA to propose a FIP before taking the predicate final action of disapproving a SIP in the states the FIP is proposed to

[302] *Virginia v. EPA*, 108 F. 3d 1397 (D.C. Cir. 1997).

[303] 42 U.S.C. 7410(c)(1)(B) (emphasis added).

cover.[304] In fact the D.C. Circuit expressly reserved judgement on this very issue the last time it was raised before the D.C. Circuit, dismissing it on administrative exhaustion grounds rather than approving EPA's approach. [305] Nor does the Supreme Court's opinion in *EME Homer* address this issue, as that opinion only determined that EPA need not provide States an additional opportunity to revise its SIP after disapproval of a SIP, not whether a FIP can be issued before disapproving a SIP in the first place.[306] If EPA does proceed with SIP denials, in the interest of cooperative federalism and in furtherance of the Clean Air Act itself, EPA should allow a reasonable time for States to address the grounds for denial before EPA promulgates a FIP.

XXXV. EPA Cannot Lawfully Issue FIP and Disapprove SIPs Based on Data Not Available at Time SIP Submissions Were Required.

As noted in the State of Arkansas' comments on EPA's proposed denial of Arkansas' proposed Good Neighbor SIP provisions for the 2015 Ozone NAAQS, EPA reevaluated the significance of contributions to downwind receptors based on data generated *after* the statutory deadline for EPA to act on approving or disapproving the Arkansas Transport SIP submission.[307] Had EPA reviewed the SIP in the timeframe required by federal law, the information available at the time—the same information that states used to inform their decisions—would not have supported a decision to disapprove the SIP for Arkansas, and subsequently would remove any statutory basis for EPA to promulgate a FIP for Arkansas. Although the D.C. Circuit has held that EPA has legal authority to propose a FIP at the same time it disapproves a SIP submission without giving the State an opportunity to fix the deficiency in the SIP submission, we are aware of no decision or statutory basis that would allow EPA to do so based on data that was unavailable to the State at the time that it made its SIP submission. On the contrary, "It is one thing to expect regulated parties to conform their conduct to an agency's interpretations once the agency announces them; it is quite another to require regulated parties to divine the agency's interpretations in advance or else be held liable when the agency announces its interpretations for the first time . . . and demands deference." [308] Accordingly, it was unreasonable and unlawful for EPA to disapprove the Arkansas submission based on data that the agency did not generate until after its statutory deadline to act on the Arkansas Transport SIP. Because EPA erred in denying the Arkansas Transport SIP, it was also not lawful for EPA to propose the Proposed Rule FIP to

[304] Contra Proposed Rule at 20,057.

[305] *EME Homer City Generation, L.P. v. E.P.A.*, 795 F.3d 118, 132 (D.C. Cir. 2015) ("petitioners argue that EPA did not have authority to promulgate certain Transport Rule FIPs because those FIPs were signed by the EPA Administrator before EPA published its disapproval of the CAIR SIPs in the Federal Register. Petitioners did not raise this issue before the Agency during notice and comment, and EPA has not denied any petition for reconsideration raising this objection. We therefore may not entertain it now").

[306] *EPA v. EME Homer City Generation, LP*, 572 U.S. at 509 & n.14.

[307] See Comment submitted by Arkansas Department of Energy and Environment, Division of Environmental Quality, on EPA-R06-OAR-2021-0801-0001, at 3-4 (April 22, 2022).

[308] *Christopher v. SmithKline Beecham Corp.*, 567 U.S. 142, 158-59 (2012).

cover Arkansas, since EPA only has the authority to issue a FIP if a state failed to submit an approvable SIP or EPA properly disapproved it.[309]

XXXVI. Requirements For EPA SIP Review.

EPA states that "In order to replace the non-EGU portion of the FIP in a state, the state's SIP must provide adequate provisions to prohibit an equivalent or greater amount of NOx emissions that contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. The non-EGU requirements of the FIP would remain in place in each covered state until a state's SIP has been approved by the EPA to replace the FIP."[310] This is not reasonable or lawful for multiple reasons.

First, a state's ability to replace the FIP must be tied to whether it has addressed the underlying nonattainment/maintenance concerns by reducing significant contribution from sources in the state below the significance threshold, (as opposed to whether it prohibits equivalent emissions to the FIP). For instance, if Arkansas is able to show that it no longer has a significant contribution to the Brazoria receptor before the final FIP deadline for non-EGU emission reduction standards (whether due to White Bluff closure or otherwise), then there would no longer be any statutory basis for EPA to impose a Good Neighbor FIP on Arkansas.

Second, given that the limits imposed in the Proposed Rule are not the same as the statewide emission reductions that EPA modeled as being sufficient to resolve any significant contribution to nonattainment or interference with maintenance of the 2015 ozone NAAQS in downwind states, as explained in detail above, EPA cannot rationally judge a SIP based on whether it reduces emissions by a greater amount than the Proposed Rule's limits would. Rather, EPA's evaluation of any SIP could not require the SIP to result in more reductions than the amount of statewide emission reductions EPA actually modeled as resulting in attainment for linked receptors. i.e., the total amount specified at the Non-EGU Screening Assessment at Figure 2.

CONCLUSION

For the reasons set forth above U.S. Steel urges that EPA withdraw the Proposed Rule in favor of allowing states the opportunity to correct any concerns that EPA may have with their SIP submittals and in the alternative for EPA to correct the errors that have been identified with respect to its Proposed Rule. If EPA makes significant changes to the Proposed Rule, which are needed, then U. S. Steel requests the opportunity to be involved in a stakeholder process and to have adequate to review and comment on any changes.

U. S. Steel appreciates the opportunity to provide comments on the Proposed Rule. If you have any questions or should you need additional information, please do not hesitate to contact me at 479-200-9743 or kjones@uss.com.

[309] 42 U.S.C. § 7410(c)(1).

[310] Proposed Rule at 20,151.

Sincerely,

Kendra A. Jones, Esq.

Assistant General Counsel - Environmental
United States Steel Corporation

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN

ADDRESSING REGIONAL OZONE TRANSPORT FOR

THE 2015 8-HOUR NAAQS.

June 21, 2022

EXHIBIT A:

Woodard and Curran Technical Support Document

TECHNICAL MEMORANDUM

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DATE: June 14, 2022

RE: EPA's Modeling Does not Sufficiently Demonstrate that Big River Steel Is a Significant Contributor to Ozone Problems at Brazoria, TX

In the following memorandum, we offer our opinion regarding the Environmental Protection Agency (EPA) proposed rule, "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard" (87 FR 20036, April 6, 2022, herein the "Proposed Rule"). We reviewed multiple documents, memorandum, and data sets related to the Proposed Rule found in the associated docket and/or provided by EPA via email and external hard drives. Our purview was restricted to the modeling and technical approach of determining significance of impact of Nitrogen Dioxide (NOx) emissions from the Big River Steel (BRS) facility in Osceola, Arkansas (AR). Our opinion based on the discussion below is succinctly summarized as the following:

EPA's modeling in support of the Proposed Rule does not sufficiently demonstrate that NOx emissions from Big River Steel significantly contribute to Ozone concentrations at the monitor in Brazoria County, Texas (TX).

1. OVERVIEW OF EPA'S FINDING RELATIVE TO BRS

During the Cross-State Air Pollution Rule (CSAPR) Update (Final October 2016), EPA developed a four-step framework to address requirements of the good neighbor provision for the 8-hour Ozone National Ambient Air Quality Standard (NAAQS): 1) identify downwind air quality problems; 2) identify upwind states that contribute enough to those downwind air quality problems to warrant further review and analysis; 3) identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems; and 4) adopt permanent and enforceable measures needed to achieve those emissions reductions.

EPA performed state-level photochemical grid modeling using the Comprehensive Air Quality Model with Extensions (CAMx)[1] showing projected 2026 AR NOx emissions could result in a predicted contribution at one downwind receptor (the Brazoria County, TX Ozone monitor, EPA number 480391004, hereafter referred

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[1] CAMx Model. https://www.camx.com/; accessed May 2022.

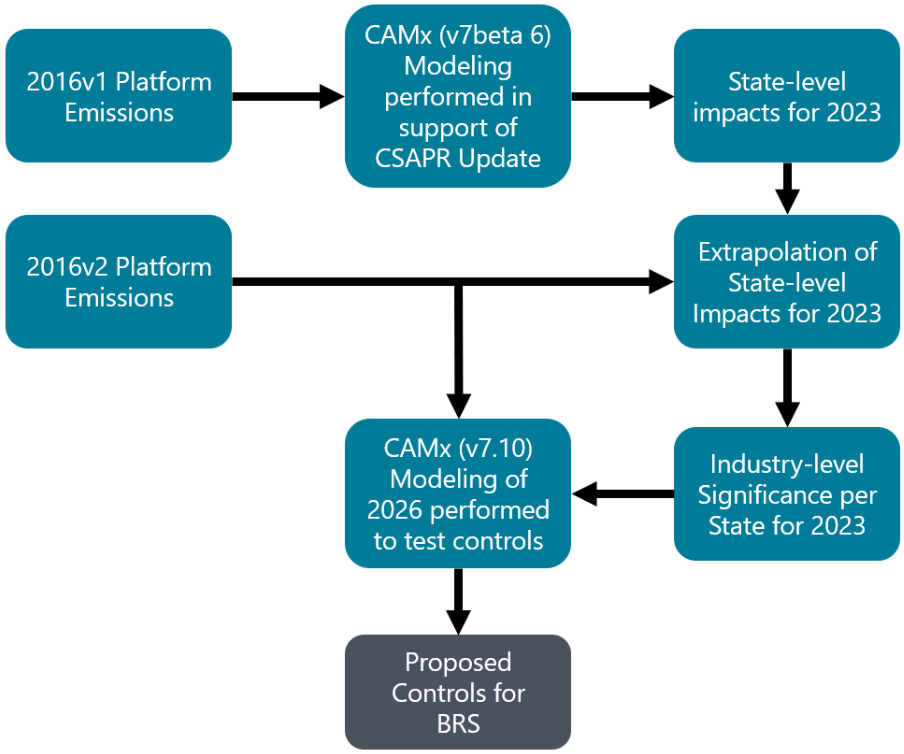
to as Brazoria) above 1 ppb (the current Ozone Significant Impact Level, or SIL) and 1% of the 2015 Ozone NAAQS. EPA thus concluded that projected AR NOx emissions in 2026 may contribute to the Brazoria, TX monitor's maintenance of attainment of the 2015 Ozone NAAQS in 2026. No other monitors projected by EPA to be "linked" to AR were shown to be in nonattainment or maintenance beyond 2023. In EPA's view, this conclusion satisfied the first two steps of the four-step framework: projected NOx emissions (2026) from AR NOx sources resulted in potential Ozone issues at a downwind out-of-state receptor (Brazoria, TX).

With AR presumably identified after steps one and two of their framework, EPA looked to satisfy step three, "identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems", by extrapolating modeling results to estimate impacts at any out-of-state ("downwind") receptor due to NOx emissions from several industries in multiple states. One of those industries evaluated was the AR steel industry, within which BRS is one facility.

To arrive at an estimate of the downwind impacts from the AR steel industry EPA used state-level modeled results for the future year 2023 from their previously performed modeling in support of the CSAPR Update[2] in combination with an emissions inventory developed as part of EPA's "2016v2 Platform"[3]. The CSAPR Update modeling results were based on an older version of the emissions platform (2016v1). For the Proposed Rule, the older CSAPR Update modeling of each state's NOx emissions for year 2023 (using projected emissions) were extrapolated to estimate the contribution from several industries within each state. Based on the extrapolated industry-level results, EPA developed control scenarios for industry-level units such that presumed downwind air quality issues would be mitigated by 2026 (2023 being deemed too soon to reasonably facilitate installation of controls). Those mitigation scenarios would be applicable to BRS, and future expansion plans associated with BRS under the Proposed Rule. The schematic in **Figure 1** represents our understanding of the general approach EPA took to begin to their four-step framework.

[2] Revised Cross-State Air Pollution Rule Update, Final Rulemaking, April 30, 2021. https://www.epa.gov/csapr/revised-cross-state-air-pollution-rule-update; accessed, May 2022.
[3] January 19, 2022. Air Quality Modeling for the 2016v2 Emissions Platform. https://www.epa.gov/air-emissions-modeling/2016v2-platform; accessed May 2022.

Figure 1: Estimated Schematic of EPA's Approach to Determine Industry-level Significance and Inform BRS NOx Emission Controls



In general, the basis for the Proposed Rule's mandate to control NOx emissions from BRS should hinge sharply on the determination that BRS's NOx emissions significantly contribute to levels of Ozone at Brazoria above the 8-hour Ozone NAAQS. This determination was never reached nor approached by EPA in the Proposed Rule. Instead, EPA considered extrapolations of state-level Ozone contributions and then, across all evaluated states, imposed controls on all sources within an industry that EPA believed could contribute to Ozone issues if that industry showed at least one instance of extrapolated significance nationally. In the discussion below, various components of EPA's technical approach to determine significance of BRS's NOx emissions relative to the Ozone concentrations at Brazoria are evaluated, and opinions offered regarding the appropriateness of EPA's findings.

2. EPA'S DATA AND THE SIGNIFICANCE OF BRS

2.1 EPA's Technical Approach Is Disconnected from EPA's Goal of Determining Significance.

In the Proposed Rule, EPA is aiming to "*provide states with as much information as the EPA can supply at this time to support their ability to submit SIP revisions to achieve the emissions reductions the EPA believes* *necessary to eliminate significant contribution [to downwind Ozone air quality issues].*"[4] EPA's responsibility under section 110 of the Clean Air Act is to mitigate emissions that ***significantly*** contribute to nonattainment or interference with maintenance of the 2015 Ozone NAAQS. The scope of their emission mitigation mandate is bounded by the ***significance*** of contribution of those emissions, such that "*reductions unnecessary to downwind attainment anywhere fall outside the Agency's statutory authority*"[5], thus prohibiting "over control" of emissions based on insignificant impacts. The ***significance*** of BRS's NOx emissions to out-of-state Ozone concentrations at a monitor roughly 850 kilometers away (Brazoria) is thus a critical question. EPA's task then, in advance of mandating controls on BRS based on Ozone predicted concentrations at Brazoria was to robustly determine the significance of BRS's NOx emissions to downwind Ozone air quality issues at Brazoria. Based on the elements of approach described below, our opinion is that EPA did not sufficiently determine the significance of BRS's NOx emissions relative to Ozone attainment at Brazoria or at any monitor.

2.2 EPA Did Not Model BRS NOx Emissions Yet Deemed Them Significant.

The main component of EPA's determination of the significance of downwind Ozone contributions from the steel industry's NOx emissions is not based on direct modeling or apportionment of the steel industry. Rather, as described in **Figure 1**, that determination of industry-level significance was made based on obsolete state-level modeling and extrapolations using outdated emission inventories. That industry-level significance was then applied to facilities within "significant" industries broadly. In other words, EPA found that the steel industry's NOx emissions were significant, thus all evaluated state's steel industries' NOx emissions were significant, thus AR's steel industry was significant, thus BRS's NOx emissions were significant. However, from all appearances and based on our understanding of the data made available by EPA, nowhere in the CAMx modeling steps described in **Figure 1** (the older CSAPR update modeling to determine industry-level significance or the Proposed Rule's modeling to test control scenarios of those "significant" industries) were BRS's NOx emissions considered. EPA has deemed BRS NOx emissions significant without ever having tested their significance via modeling.

The modeling performed by EPA in support of CSAPR to determine BRS's significance by way of extrapolation used the 2016v1 EPA emission platform; the modeling performed by EPA to test control scenarios of significant industries used the 2016v2 EPA emission platform. Neither of these platforms include BRS NOx emissions. The 2016v1 and 2016v2 EPA emissions platforms consist of inventory "cases" that represent the years 2016, 2023, 2026, and 2032 with the abbreviations 2016fj, 2023fj, 2023fj, and 2032fj, respectively. The abbreviation gives insight into the foundational source of the emissions data from which the projected future-year inventories are derived: in the abbreviation 2026fj_16j, 2026 is the year represented by the emissions (a future year in this case, developed by projection factors); the "f" represents the base year emissions modeling platform iteration – "f" was developed from the 2014 National Emission

[4] Proposed Rule "Executive Summary".

[5] EPA v. EME Homer City Generation, L.P., 572 U.S. 489 (2014).

Inventory (NEI); the "j" stands for the tenth configuration of emissions modeled for that modeling platform.[6] For all inventories with the "f" base year, BRS was not featured. This is due to BRS not becoming active until well into 2015. **Table 1** presents our understanding of EPA's emissions platforms used in CAMx modeling, the application of the results of that modeling, and whether BRS NOx emissions were included. EPA's approach to determine significance NOx emissions from states (e.g., AR) and industries within those states (e.g., the steel industry) and the determination and testing of NOx control scenarios does not include BRS's NOx emissions.

Table 1: Summary of Emissions Cases Used in EPA CAMx Modeling

EPA Emissions Platform	Emissions Case Used In EPA CAMx Modeling	EPA Application of Results	Were BRS NOx Emissions Included?
2016v1	2016fj	Baseline case	No
2016v1	2023fj	Determination of significant states and significant industries in those states	No
2016v2	2026fj	Determination of industry specific control scenarios	No

Table 2 presents an excerpt from EPA's summary of NOx emissions from non-Electricity Generating Unit (Non-EGU) point sources used in the modeling as shown in inventory data provided within the Proposed Rule docket. EPA used no BRS emissions under inventory 2023fj (EPA's basis for significance modeling) nor in inventory 2026fj (EPA's basis for the control testing modeling). BRS NOx emissions do appear in other inventories (2017gb, 2018gc, 2019 NEI20210914), however, these inventories noted by EPA as not having been modeled[7].

Table 2: Summary of BRS NOx Emissions Inclusion in EPA Non-EGU Inventories

Facility Name	Facility ID	Pollutant	2016fj tpy	2017gb tpy	2018gc tpy	2019NEI 20210914 tpy	2023fj tpy	2026fj tpy	2032fj tpy
Big River Steel LLC	18122211	NOX	-	283.41	290.19	273.74	-	-	-

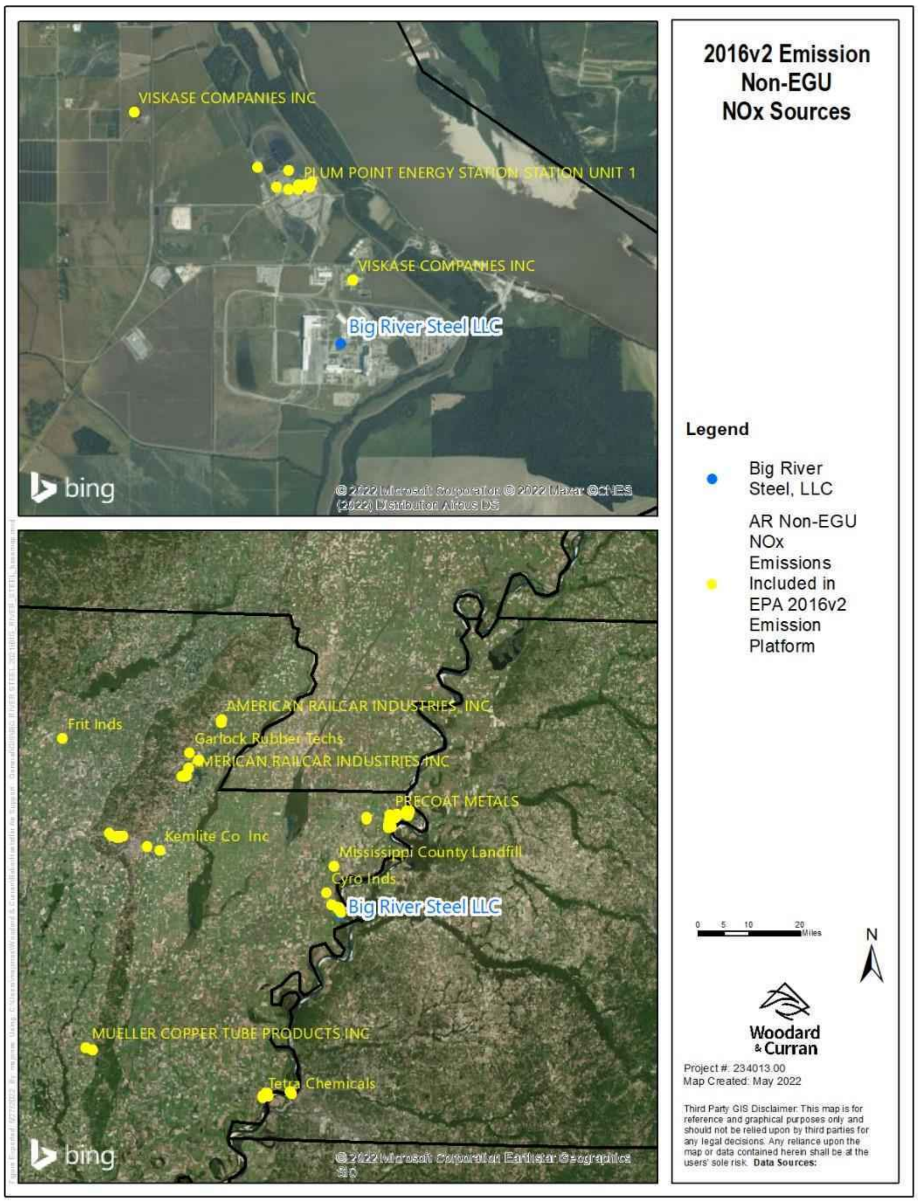
Further, **Figure 2** presents a mapping of the emission sources in northeastern AR that were included in EPA's 2016v2 emissions platform (which were used in EPA's control scenario modeling). Yellow dots indicate AR sources included. BRS was not present (noted by blue dot location). Thus, EPA has applied significance

[6] EPA Document EPA-HQ-OAR-2021-0668-0064. Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform.
[7] EPA Document EPA-HQ-OAR-2021-0668-0105, Content PDF: "while 2017, 2018, and 2019 data provided for additional context although 2017-2019 were not modeled."

to BRS's NOx emissions, and arrived at control scenarios for BRS without ever having performed modeling capable of demonstrating that significance.

Any inference in the Proposed Rule as to the significance of BRS's NOx emissions relative to the Ozone concentrations at Brazoria is based on modeling that did not consider BRS's NOx emissions and is inconsequential.

Figure 2: EPA 2016v2 Emissions Sources in Northeast Arkansas



Source: EPA 2016v2 Emissions Platform Data; https://gaftp.epa.gov/Air/emismod/2016/v2/2016emissions/by_state/AR/; accessed May 2022.

2.3 EPA Used Extrapolations of Obsolete Modeling Results Based on an Inaccurate Emissions Inventory.

The state-level modeling performed in support of the CSAPR Update that was relied on for the determination of significance of the steel industry and thus BRS used an obsolete "beta" version of CAMx (version 7beta 6), an obsolete version of the Weather Research and Forecasting Model (WRF, version 3.8, released in 2016; WRF is now at version 4.4) and an older obsolete emissions inventory (2016v1)[8]. Version "7beta 6" was a pre-release of CAMx version 7.00, which has been flagged by the model developer as a version with "several critical bugs associated with major updates to the input files"[9] and that organizations using CAMx should "use later versions." EPA's CAMx model was a "beta" pre-release version of 7.00 and thus contained these critical bugs. Since that time, multiple versions of CAMx with corrective updates have been issued by the developer (version 7.10 in January 2021 and recently version 7.20 in May of 2022). EPA should have updated the modeling with a corrected version of CAMx or could have used EPA's own photochemical grid model that they provide ongoing development support for, the Community Multi-scale Air Quality Model (CMAQ) model[10], which they used for other aspects of the modeling study (development of initial and boundary concentrations).

Were an applicant to use an obsolete model with listed "bugs" by the developer while a valid alternative was available and incorporated obsolete emissions to determine the significance of a facility, EPA would reject any results submitted for review and require the applicant use the latest version of an approved alternative model and relevant representative emissions[11]. In addition, EPA recently disapproved of a state's implementation plan regarding the 2015 8-hour Ozone NAAQS on the basis that in forming their opinion on downwind significance, the state relied on older data and modeling[12]. EPA disapproved of the state's finding relative to significance since the modeling data used was obsolete. EPA is not holding their modeling to the same rigor with which they hold applicants or states. In using the older CSAPR Update modeling which relied on a model with known errors and obsolete emissions, EPA did not use the latest

[8] Air Quality Modeling Technical Support Document for the Final Revised Cross-State Air Pollution Rule Update, March 2020. https://www.epa.gov/sites/default/files/2021-03/documents/air_quality_modeling_tsd_final_revised_csapr_update.pdf; accessed May 2022.
[9] CAMX.com, note on version 7.00. https://camx-wp.azurewebsites.net/download/source/; accessed May 2022.
[10] EPA CMAQ model. https://www.epa.gov/cmaq; accessed May 2022.
[11] EPA, 40 CFR Part 51; https://www.epa.gov/sites/default/files/2020-09/documents/appw_17.pdf; accessed May 2022.
[12] Air Plan Disapproval; Nevada; Interstate Transport of Air Pollution for the 2015 8-hour Ozone National Ambient Air Quality Standards; May 24, 2022. 87 FR 31485.

version of an approved alternative model and did not use relevant representative emissions to determine significance of industries.

EPA leveraged obsolete information (old model and old emissions) and made extrapolations of that information to determine industry-level significance of NOx emissions to downwind Ozone problems and then applied that industry-level significance to BRS. Those industry-level extrapolations were based on the 2016v2 emissions platform, which has been shown to have substantial errors[13]. EPA's stated reason for why they used obsolete models (CAMx 7beta 6, WRF 3.8) incorporating obsolete emissions (2016v1) to feed their industry-level extrapolations applied to BRS was "*the air quality modeling for this proposed rule was not completed in time to support the assessment.*"[14] Photochemical grid modeling is highly complex and takes substantial time to perform, especially to arrive at explicit facility-level impacts. EPA did not have time to complete the appropriate quality of modeling to support the determination of facility or industry-level significance, and thus relied on obsolete modeling with known bugs and extrapolations of that modeling based on inaccurate data (2016v2 emissions) to determine significance of industries in each state and applied that significance to facilities like BRS. Instead of moving forward with a determination of significance that would not pass their own thresholds of appropriateness with which they judge applicants' modeling analyses, EPA should have performed the explicit state, industry, and facility-level modeling using latest model versions and appropriate emissions to appropriately determine the significance of NOx emissions from industrial facilities.

Any inference in the Proposed Rule as to the significance of BRS's NOx emissions relative to the downwind Ozone concentrations at Brazoria is based on extrapolations of obsolete modeling data using inaccurate emissions that don't reflect BRS and is inconsequential.

2.4 EPA Defines 0.01 Ppb as A Threshold of Significance by Subjective Visual Interpretation of a Histogram Plot.

To determine whether AR steel industry's NOx emissions were significantly contributing to downwind Ozone concentrations at monitors, EPA defined a new (and heretofore unused in regulatory applications or review) threshold concentration, 0.01 ppb of Ozone. EPA has previously definitively stated that 1 ppb is a threshold of significance at the project level for the 2015 Ozone NAAQS (8-hour Ozone SIL)[15]. In other words, a single project's emissions could result in downwind Ozone concentrations up to 1 ppb before even that single project was considered significant. However, in the Proposed Rule, EPA defined a substantially more

[13] Arkansas Division of Environmental Quality Comments; Docket No. EPA-R06-OAR-2021-0801, April 22, 2022.

[14] Proposed Rule, footnote 161.

[15] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program. https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf. Accessed May 2022.

stringent level of significance for the entirety of an industry (not just a single project) within a state. While a single AR steel project could have been deemed insignificant with respect to contribution to Ozone problems by adherence to the EPA's 2015 Ozone SIL of 1 ppb, the entire AR steel industry would now be deemed significant by a downwind concentration of only 0.01 ppb, a level ***100 times lower*** than the official SIL. This stringency is unfounded and would require a substantial amount of supporting analysis (e.g., statistical analysis evaluating the variation in the Ozone 8-hour design value at each monitoring site across the nation) to prove that 0.01 ppb is indeed a threshold above which out-of-state NOx emissions would significantly impact Ozone attainment. EPA has published guidance to instruct other agencies on how to determine and justify Ozone significance values if proposed as an alternative to EPA's 1 ppb level[16]. EPA did not follow their own guidance in this case.

The required quality of supporting analysis was not performed by EPA to arrive at 0.01 ppb. Instead, the analysis used to determine this increased level of stringency beyond the existing 1 ppb SIL was a visual interpretation of a histogram plot. EPA described it thus

> *Initially, there is a fairly steep drop in contributions with a breakpoint between roughly 0.04 and 0.06 ppb followed by a steady decline to 0.01 ppb. Beyond 0.01 ppb the shape of the distribution is much flatter. The data suggest that perhaps 0.05 ppb or 0.01 ppb could serve as breakpoints in the data. Based on the distribution, the 0.01 ppb provides a meaningful conservative breakpoint for screening out non-impactful industries from the Non-EGU analysis in this proposed rule.*[17]

Figure 3 presents the histogram used in EPA's threshold of significance "analysis." In the histogram, each bar represents the maximum contribution to a downwind receptor from a particular industry. EPA did not readily disclose the industries in this analysis in order to provide greater resolution of the shape of the distribution at the lower end of the values. EPA's determination based on their visual interpretation of a ranked histogram is that a 0.01 ppb concentration resultant from AR's steel industry will significantly impact a downwind receptor (like Brazoria) attaining or maintaining the Ozone NAAQS because in general there are few industries that result in Ozone concentrations lower than 0.01 ppb out of state. This argument is not an argument for significance. EPA has not rigorously demonstrated that 0.01 ppb is significant relative to the Ozone NAAQS. EPA has only demonstrated that 0.01 ppb is a subjective level of reference below which few industries have resultant concentration impacts. EPA should have used their previously determined level of significance of 1 ppb for the 2015 Ozone NAAQS.

[16] EPA, Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program. https://www.epa.gov/sites/default/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf. Accessed May 2022.

[17] Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026, February 28, 2022. Docket No. EPA-HQ-OAR-2021-0668.

Any inference in the Proposed Rule as to the significance of BRS's NOx emissions relative to downwind Ozone concentrations at Brazoria is based on a subjective reference concentration of 0.01 ppb and is inconsequential.

Figure 3: Taken from Figure A-1 of the "Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026"

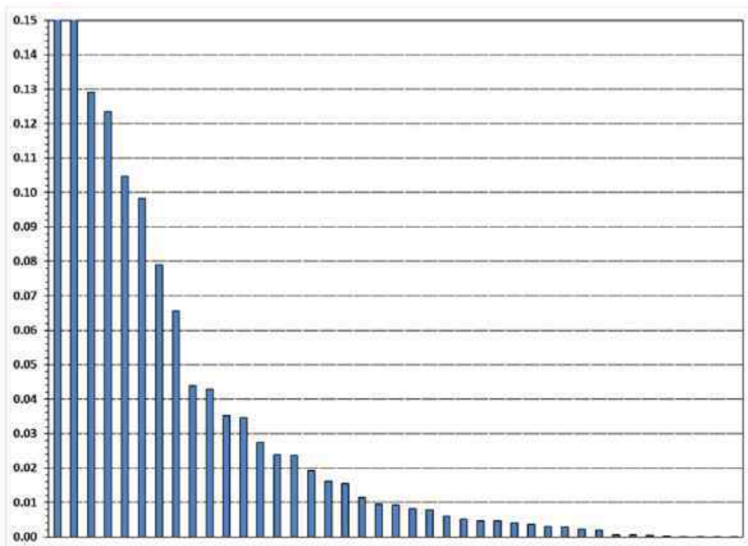


Figure A-1. Rank-ordered maximum downwind contributions from individual industries

2.5 EPA's Approach Applies Significance to BRS Without Appropriate Basis.

The CAMx model allows for the modeler to "tag" certain sources or groups of sources to determine the portion of predicted concentration at a receptor that could be attributed to that source or group of sources. In the obsolete modeling that EPA leveraged in the determination of significance, EPA did not tag individual industries, but rather only tagged 53 groups of sources, comprised predominantly of states (other tags were related to biogenic emissions, offshore emissions, international emissions, tribal emissions, and boundary condition emissions). No explicit apportionment of individual industries was performed in the modeling. Rather, as stated in Section 2.2, results of obsolete modeling were extrapolated in a rough estimate of receptor concentrations attributable to different industries. EPA then compared those extrapolated industry results to the subjective reference level of 0.01 ppb (Section 2.3).

Based on EPA's approach, only one state's steel industry is "significantly" contributing to potential ozone issues at a downwind receptor out-of-state. EPA did not readily disclose which state's steel industry was "significant" nor what downwind out-of-state receptors were impacted by that state's steel industry. EPA disclosed simply that the steel industry from one state featured maximum extrapolated concentrations above 0.01 ppb at 11 downwind receptors - see **Figure 4** which presents EPA's Table A-3 of their screening assessment[18]. The impacts from all evaluated steel industry emissions are noted with an arrow. Note that NOx emissions from one state's steel industry featured an extrapolated concentration more than 0.01 ppb.

Figure 4: Taken from Table A-3 of the "Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026"

Table A-3. Estimated Total, Maximum, and Average Contributions from Each Industry, and Number of Receptors with Contributions >= 0.01 ppb for 2023

Industry	# Facilities with Units > 100tpy	# Units > 100 tpy	Ozone Season Emissions	Total Contribution	Max Contribution	Average Contribution	# Receptors with Contributions >= 0.01 ppb	# States with Highest Contribution >= 0.01 ppb
Pipeline Transportation of Natural Gas	144	399	34,343	**1.679**	**0.287**	**0.084**	**12**	**12**
Cement and Concrete Product Manufacturing	61	84	36,244	**1.871**	**0.231**	**0.094**	**19**	**13**
Iron and Steel Mills and Ferroalloy Manufacturing	14	43	4,622	**0.577**	**0.129**	**0.029**	**11**	1
Basic Chemical Manufacturing	38	78	9,612	**0.293**	**0.123**	**0.015**	**9**	**2**
Glass and Glass Product Manufacturing	38	53	12,059	**0.695**	**0.105**	**0.035**	**11**	**7**
Petroleum and Coal Products Manufacturing	47	94	8,163	**0.733**	**0.098**	**0.037**	**12**	**6**
Metal Ore Mining	9	21	17,778	**0.687**	**0.079**	**0.034**	**15**	**3**
Lime and Gypsum Product Manufacturing	31	60	8,856	**0.531**	**0.066**	**0.027**	**13**	**3**
Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	16	27	3,680	**0.162**	**0.044**	0.008	**3**	1
Pulp, Paper, and Paperboard Mills	46	73	6,773	**0.306**	**0.043**	**0.015**	**11**	**3**
Oil and Gas Extraction	59	139	9,150	**0.207**	**0.035**	**0.010**	**9**	**2**
Nonmetallic Mineral Mining and Quarrying	8	18	3,808	**0.167**	**0.035**	0.008	**4**	1
Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing	10	16	1,779	**0.152**	**0.027**	0.008	**7**	**2**
Other Chemical Product and Preparation Manufacturing	7	8	683	**0.074**	**0.024**	0.004	**3**	1
Clay Product and Refractory Manufacturing	1	2	1,098	**0.088**	**0.024**	0.004	**4**	1
Chemical and Allied Products Merchant Wholesalers	1	4	573	**0.032**	**0.019**	0.002	**2**	1
Natural Gas Distribution	6	17	1,027	**0.058**	**0.016**	0.003	1	1
Water, Sewage and Other Systems	6	6	375	**0.069**	**0.016**	0.003	**4**	1
Pharmaceutical and Medicine Manufacturing	2	2	300	**0.057**	**0.011**	0.003	1	1
Grain and Oilseed Milling	4	4	376	**0.042**	0.009	0.002	0	0
Lessors of Real Estate	2	2	138	**0.037**	0.009	0.002	0	0
Nonferrous Metal (except Aluminum) Production and Processing	1	4	408	**0.025**	0.008	0.001	0	0
Sugar and Confectionery Product Manufacturing	5	10	1,068	**0.043**	0.008	0.002	0	0
Electric Power Generation, Transmission and Distribution	4	4	296	**0.039**	0.006	0.002	0	0
Engine, Turbine, and Power Transmission Equipment Manufacturing	2	2	112	**0.020**	0.005	0.001	0	0
Agriculture, Construction, and Mining Machinery Manufacturing	1	1	73	**0.012**	0.005	0.001	0	0
Colleges, Universities, and Professional Schools	4	4	263	**0.030**	0.005	0.002	0	0
Coal Mining	5	5	283	**0.015**	0.004	0.001	0	0
Plastics Product Manufacturing	2	2	126	**0.012**	0.004	0.001	0	0
Architectural, Engineering, and Related Services	2	2	117	**0.013**	0.003	0.001	0	0
Motor Vehicle Parts Manufacturing	1	1	62	**0.011**	0.003	0.001	0	0
Advertising, Public Relations, and Related Services	1	1	51	0.009				
Waste Treatment and Disposal	5	5	376	0.010				
National Security and International Affairs	1	1	42	0.002				
Support Activities for Mining	1	1	56	0.003				
Beverage Manufacturing	1	1	45	0.002				
Veneer, Plywood, and Engineered Wood Product Manufacturing	1	1	9	0.001				
Scientific Research and Development Services	1	1	78	0.001				
Alumina and Aluminum Production and Processing	1	1	13	0.000				
Other Food Manufacturing	1	1	45	0.000				
Office Administrative Services	1	1	5	0.000				
Total	591	1,199	164,962	8.77				
Tier 1 Industries	257	579	87,267	4.82				
Tier 2 Industries	171	326	51,182	2.55				
Tier 1 Industries (% of Total)	43%	48%	53%	55%				
Tier 2 Industries (% of Total)	29%	27%	31%	29%				

Legend

	Maximum Contribution	# Receptors with Contributions >=0.01 ppb	Total Contribution	# States with Highest Contribution >= 0.01
Break Points	0.01 to 0.04	> 1 to 9	0.1 to 0.4	> 1 to 9
	>= 0.05	>= 10	>= 0.5	>= 10

1st Tier of Industries for Further Analysis Based on AQ Contributions
These industries (1) have a maximum contribution to any one receptor of >0.10 ppb AND (2) contribute >= 0.01 ppb to at least 10 receptors.

2nd Tier of Industries for Further Analysis Based on AQ Contributions
These industries either have:
(1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or
(2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors

While the 0.01 ppb concentration threshold is not a level of significance in our opinion (Section 2.3), in **Figure 4**, EPA has found that all other state's steel industries do not "significantly" contribute to Ozone concentrations at downwind receptors. However, while EPA demonstrates that only one state's steel industry has downwind impacts of 0.01 ppb and is thus "significant", EPA applies "significance" to the steel industry in 23 states. Even though the AR steel industry and BRS specifically may have no impact on the 11 receptors identified as having extrapolated concentrations above the 0.01 ppb subjective reference level,

[18] Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026, February 28, 2022. Docket No. EPA-HQ-OAR-2021-0668

EPA has identified AR steel and thus BRS NOx emissions as significant to downwind receptors based on another state's (and thus another facility or facilities) emissions.

We applied the methodology EPA used to develop the table of industry-level significance in **Figure 4** using receptor specific calibration factors calculated at each maintenance and non-attainment receptor (except for California which was excluded from EPA's analysis). The calibration factors were calculated using the procedures outlined in EPA's "ozone_transport_policy_analysis_final_rule_tsd_0.pdf" document. The base case CAMx model results for both 2016 and 2023 and the state-specific anthropogenic NOx emission totals for 2016 and 2023 used for the calibration factor calculation were obtained from the EPA's air quality assessment tool (AQAT)[19]. Attachment 1 to this memorandum outlines our understanding of EPA's extrapolation approach.

An inventory of NOx emissions from BRS was then provided to Woodard & Curran as derived from BRS's 2021 emission inventory of actual NOx emissions of all operational units at the BRS facility that could potentially fit under any of the furnace or boiler types defined under the Proposed Rule. These 2021 actual NOx emissions are conservative relative to the NOx emissions EPA has within their unmodeled 2017gb, 2018gc, or 2019NEI inventories (see **Table 2**), but are reflective of current normal production levels. However, a 5% safety factor was added to include a measure of conservatism. These emissions were added to the EPA 2023fj NOx emission inventory characterized as within the AR Steel industry (NAICS code 331110). The extrapolated contribution of BRS to the 8-hour Ozone design value concentration at each desired maintenance and non-attainment receptor was then calculated following EPA's methodology by multiplying the total state contribution from the 2023 base case CAMx modeling result by the ratio of BRS emissions vs. total anthropogenic emissions and then by the EPA calibration factor for each receptor. **Table 3** presents the results of our analysis using EPA's methodology for EPA's 2023fj AR Steel NOx inventory, that inventory plus BRS (with conservative safety factor), and BRS's NOx emissions alone.

It should be noted, that based on our understanding of the extrapolation approach, EPA does not consider distance from a receptor within a state. The calibration factors are based on state-level apportionment data and are not capable of considering the location of an emission source within a state (see Attachment 1). For instance, a 10 ton per year NOx source at the southern border of AR (less than 450 kilometers from Brazoria) would be extrapolated for contribution at Brazoria using the same factor as a 10 ton per year NOx source at the northern border of AR (more than 900 kilometers from Brazoria), despite the fact that the northern source would contribute less at Brazoria than the southern source (see Section 3.2 for a modeling analysis highlighting the importance placed on source-receptor geography). BRS is in the northeast corner of the state, some 850 kilometers away from Brazoria while many more NOx sources are in the southern portion of AR and less than 450 kilometers from Brazoria. Thus, applying the state-wide calibration factor for BRS is highly conservative. However, even with this conservatism and the added conservatism within the emissions estimate, neither the EPA's AR Steel inventory, nor the inventory with BRS added, nor BRS

[19] EPA's "Ozone AQAT Proposal", Proposed Rule document EPA-HQ-OAR-2021-0668-0117.

alone would have an extrapolated maximum downwind impact above the 0.01 ppb subjective reference level.

BRS has a component of operations that has yet to come online but is anticipated to become active prior to the year 2026 (EPA's target year for proposed control implementation).[20] We therefore considered the additional scenario where the expanded operations were added to that of BRS, and extrapolated impacts for comparison to the 0.01 ppb subjective reference level (see **Table 3**). As noted, even with the additional NOx emissions from the expanded operations and conservative safety factors, BRS's maximum downwind impact is below the 0.01 ppb reference level.

Table 3: Extrapolated Steel Industry Contributions Based on EPA's Methodology

Monitor / Receptor			EPA 2023fj AR Steel Inventory [1] (ppb)	EPA 2023fj AR Steel Inventory + BRS [2] (ppb)	BRS [2] (ppb)	BRS [2] + Expansion [3] 2026 (ppb)
Site ID	State	County				
40278011	Arizona	Yuma	0.00E+00	0.00E+00	0.00E+00	0.00E+00
80350004	Colorado	Douglas	7.76E-06	1.68E-05	9.03E-06	1.65E-05
80590006	Colorado	Jefferson	1.97E-06	4.27E-06	2.30E-06	4.20E-06
80590011	Colorado	Jefferson	2.75E-06	5.95E-06	3.20E-06	5.86E-06
90010017	Connecticut	Fairfield	2.87E-04	6.21E-04	3.34E-04	6.11E-04
90013007	Connecticut	Fairfield	6.06E-04	1.31E-03	7.06E-04	1.29E-03
90019003	Connecticut	Fairfield	4.90E-04	1.06E-03	5.71E-04	1.05E-03
90099002	Connecticut	New Haven	5.97E-04	1.29E-03	6.96E-04	1.27E-03
170310001	Illinois	Cook	8.31E-05	1.80E-04	9.69E-05	1.77E-04
170310032	Illinois	Cook	1.25E-04	2.70E-04	1.45E-04	2.66E-04
170310076	Illinois	Cook	4.64E-05	1.00E-04	5.40E-05	9.88E-05
170314201	Illinois	Cook	1.44E-04	3.11E-04	1.68E-04	3.07E-04
170317002	Illinois	Cook	3.77E-04	8.17E-04	4.40E-04	8.04E-04
320030075	Nevada	Clark	8.10E-07	1.75E-06	9.43E-07	1.73E-06
420170012	Pennsylvania	Bucks	3.33E-04	7.20E-04	3.87E-04	7.09E-04
480391004	Texas	Brazoria	4.56E-03	9.87E-03	5.31E-03	9.72E-03
481210034	Texas	Denton	4.26E-03	9.23E-03	4.97E-03	9.09E-03
482010024	Texas	Harris	2.31E-03	4.99E-03	2.69E-03	4.92E-03
482010055	Texas	Harris	3.71E-03	8.04E-03	4.33E-03	7.92E-03
482011034	Texas	Harris	3.67E-03	7.96E-03	4.28E-03	7.83E-03
482011035	Texas	Harris	3.57E-03	7.72E-03	4.15E-03	7.60E-03
490110004	Utah	Davis	1.81E-06	3.92E-06	2.11E-06	3.86E-06
490353006	Utah	Salt Lake	1.52E-06	3.29E-06	1.77E-06	3.25E-06
490353013	Utah	Salt Lake	9.91E-07	2.15E-06	1.15E-06	2.11E-06

[20] Exploratory Ventures, LLC , an affiliate of BRS, has commenced construction of a new scrap to steel products mill on a site adjacent to BRS (the "EV Facility"). The EV Facility and related NOx emissions from the emission units subject to regulation under the Proposed Rule will be similar to those of the BRS facility. I.e., the existing BRS scrap to steel mill includes two EAFs and supporting equipment, and the new EV Facility will also have two EAFs and supporting equipment. The "BRS Expansion" scenario accounts for all sources at the existing mill potentially within the definition of an emission unit covered by the Proposed Rule regardless of whether each unit has PTE below or above 100 tpy, and also accounts for the same sources at the new EV Facility.

490570002	Utah	Weber	1.64E-06	3.54E-06	1.91E-06	3.49E-06
490571003	Utah	Weber	1.64E-06	3.55E-06	1.91E-06	3.49E-06
550590019	Wisconsin	Kenosha	5.63E-04	1.22E-03	6.56E-04	1.20E-03
550590025	Wisconsin	Kenosha	1.24E-03	2.69E-03	1.45E-03	2.65E-03
551010020	Wisconsin	Racine	5.34E-04	1.16E-03	6.22E-04	1.14E-03
# of Receptors with Contribution > 0.01 ppb			**0**	**0**	**0**	**0**
Maximum Downwind Contribution (ppb)			**4.56E-03**	**9.87E-03**	**5.31E-03**	**9.72E-03**

Notes:
[1] Based on EPA 2023fj emission inventory, sum of AR annual NOx sources under NAICS code 331110 (496.25 tons)
[2] BRS annual NOx emissions (550.578 tons) taken as actuals from the most recent year of operation (2021) plus a conservative safety factor of 5%.
[3] Expansion annual NOx emissions (507.523 tons) taken as projected actuals based on current operations of existing BRS site plus a conservative safety factor of 5%.

Based on EPA's approach, which is highly conservative for BRS given its distance from Brazoria relative to other NOx sources within AR, it is clear that 1) BRS's NOX emissions do not contribute above the subjective reference level of 0.01 ppb at any downwind receptors, nor at Brazoria specifically, and 2) EPA is attributing significance to BRS NOx emissions based on extrapolated concentrations using emissions from another state and thus another facility or facilities. This is inappropriate.

Any inference in the Proposed Rule as to the significance of BRS's NOx emissions relative to downwind Ozone concentrations at Brazoria is unsupported by EPA's extrapolation methodology, is based on another state's emissions, and is inconsequential.

2.6 EPA's Modeling Has Substantial Uncertainty and Suspect Capability to Predict A 0.01 ppb Level of Significance.

Notwithstanding the discussion in previous sections of this memorandum, EPA determined that 0.01 ppb of Ozone is a "significant" threshold of contribution to downwind Ozone problems from industry (Section 2.4). In addition, EPA has determined that AR NOx emissions may impact the status of Ozone maintenance at Brazoria. Thus, the accuracy and capability of EPA's model to resolve a 0.01 ppb variation in Ozone concentration and the model's accuracy at Brazoria is critical in understanding the veracity of the estimated impact as extrapolated for the steel industry and applied to BRS at Brazoria. **Table 4** presents verification statistics of EPA's modeling relative to Brazoria[21].

Table 4: Verification Statistics of EPA's CAMx Modeling for at Brazoria (verification year 2016)

Receptor	r^2 Model vs Obs.	Standard Deviation of Model (ppb)	Correlation coefficient Model vs. Obs (r)	Root Mean Square Error of Model (ppb)	Normalized Mean Bias (ppb)
Brazoria, TX, EPA Monitor #480391004	0.37	8.13	0.61	10.61	-13.01

[21] EPA's "CAMx 2016v2 MDA8 O3 Model Performance Stats by Site.xlsx"; Proposed Rule document EPA-HQ-OAR-2021-0668-0071.

According to EPA's disclosed verification statistics, the square of the correlation coefficient (r^2) is low (0.37). r^2 is a measure of how much variation seen in the model can be explained by actual variation in observation. A r^2 of 0.37 indicates that only 37% of the variation predicted by the model at Brazoria can actually be explained by observation. In other words, the model varies significantly more at the receptor than what is seen in reality. **Figure 5** presents the standard deviation EPA calculated at Brazoria for observations during the verification year (2016) and for the model predictions of 8-hour Ozone concentrations. The model over-predicts the variation at Brazoria by more than double. This has implications for use of a threshold of 0.01 ppb and the model's capability in predicting such a relatively small variation in concentration. Given the model's significantly higher degree of variation at Brazoria, substantial false positive predictions of a 0.01 ppb concentration would be likely. The model's high level of variation is poorly connected to actual changes in Ozone concentrations in general at all receptors, and at Brazoria in specific.

The model's prediction accuracy as measured by the root mean square error (RMSE) statistic at Brazoria (10.61 ppb) is generally average (at the 55th percentile) among other receptors (see **Figure 6**). This indicates that the model's capability at Brazoria is generally average relative to the model's accuracy across all the receptors but is still relatively high at over 10 ppb. This level of inaccuracy (10 ppb) is over 1,000 times greater than the threshold of significance that EPA is leveraging the model for at Brazoria (0.01 ppb). For many other receptors, the inaccuracy is higher, up to over 24 ppb in RMSE, an error 2,400 times greater than the threshold EPA is applying the model against.

Figure 5: EPA Calculated Standard Deviation (SD) of Observations and Model Predictions at All Receptors

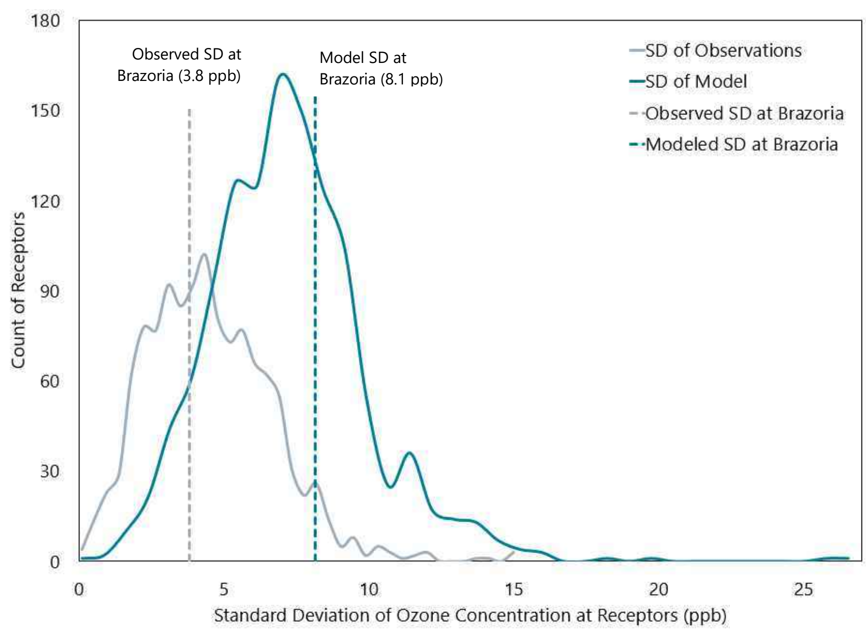
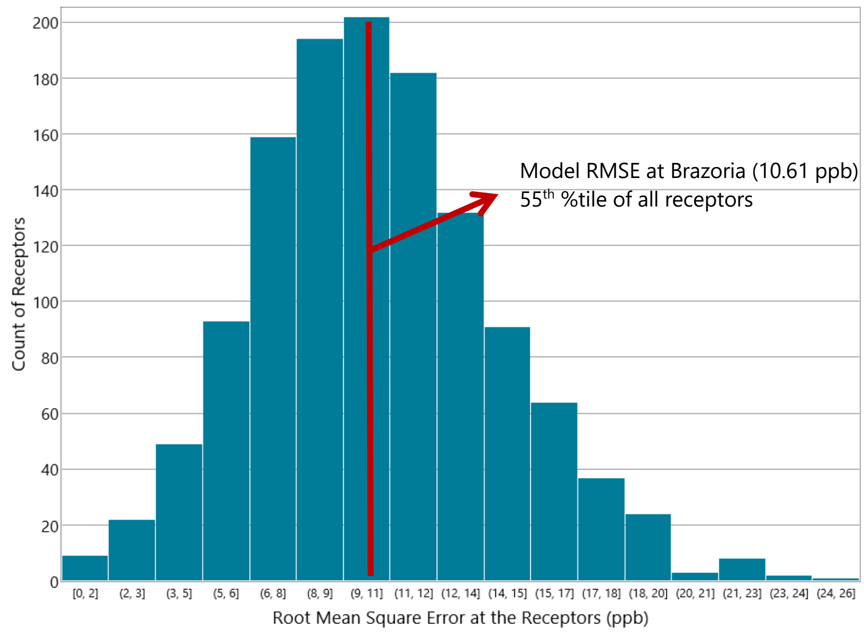


Figure 6: Model Root Mean Square Error at All Receptors vs Brazoria



Most receptors (54%) are below what literature has found to be a minimum threshold of model-to-observation correlation skill (r=0.5) for photochemical grid models like CAMx[22]. This is an important deficiency since, as discussed in Section 2.5, significance of BRS's NOx emissions at Brazoria is based on model results of other emissions at other receptors. EPA has applied significance to the steel industry based on extrapolations of one state's modeled impacts at multiple receptors (see Section 2.5). Thus, considering the broad multi-receptor application of modeling results employed by EPA, the majority of receptors being below the literature's minimum correlation threshold, would attach deficiency to the majority of the model's results, including the extrapolation applied to results at Brazoria. Further, a vast majority of receptors (81%) are below what literature considers the threshold of "very good" capability of photochemical grid models (r=0.75; see **Figure 7**).

Many receptors (31%) are outside of what literature has found to be a minimum window of model bias (normalized mean bias, NMB = <+/-15%). A vast majority of receptors (79%) are outside the window of a good photochemical grid model (NMB=+/-5%), meaning the model has substantially more model bias than typically seen in the more skilled model configurations verified. The model's bias at Brazoria (NMB=-13.01

[22] Emery et al (2017). Recommendations on statistics and benchmarks to assess photochemical model performance. Journal of A&WMA. https://www.tandfonline.com/doi/full/10.1080/10962247.2016.1265027; accessed May 2022.

ppb) is nearly at the minimum threshold of skill considered in literature and is well outside the bias window of a what literature considers a "very good" performing photochemical model (see **Figure 8**).

These verification statistics lead us to the opinion that the EPA model is largely incapable of the level of accuracy and consistency that would support applying a threshold of significance of 0.01 ppb to the model's results at Brazoria and at a majority of other receptors. The model would not reliably be able to predict whether or not BRS's NOx emissions would actually contribute 0.01 ppb and thus "significance" at this level based on the model would not be reliable.

Figure 7: Model-Observation Correlation Coefficients at All Receptors vs. Brazoria

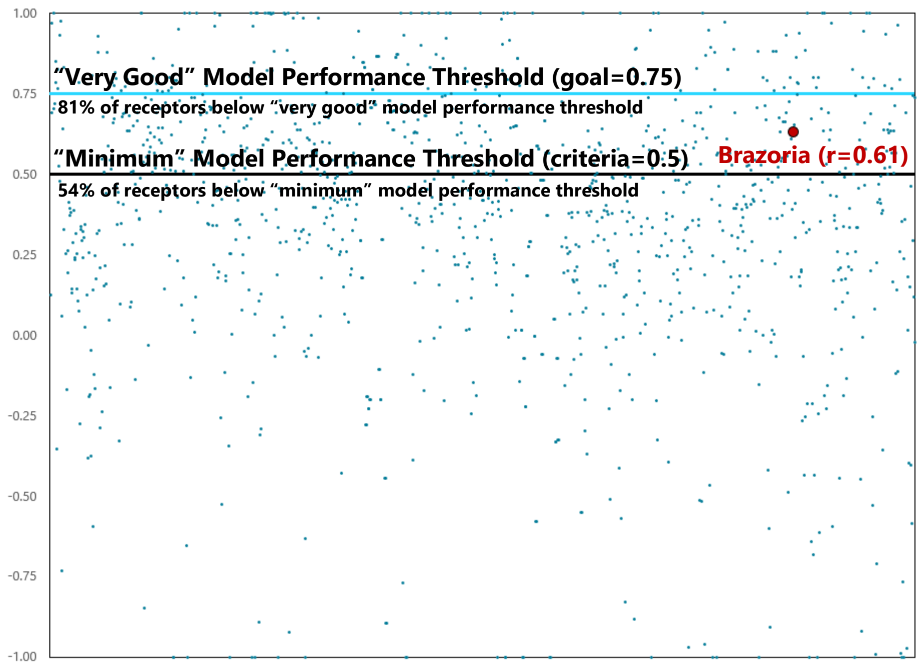
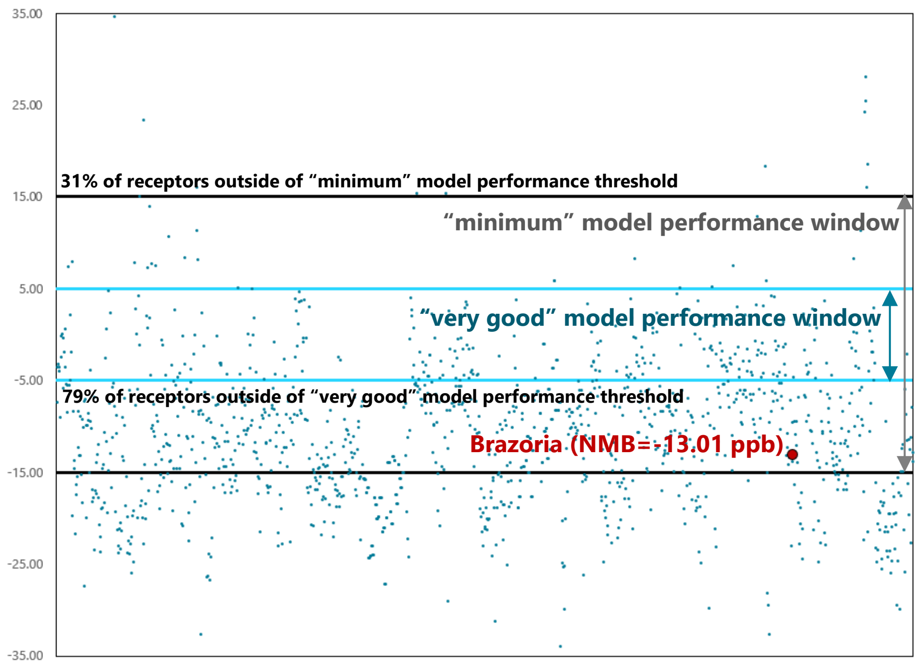


Figure 8: Normalized Mean Bias at All Receptors vs. Brazoria



In addition to the statistical model uncertainty and capability, review of data provided by EPA uncovered several inconsistencies that would contribute to a general uncertainty in results and a gap in ability to make precise determinations of significance of (in general) the steel industry's or (specifically) BRS's NOx emissions. For instance, based on the contents of several "readme" files which appear to be exchanges between EPA modelers, multiple versions of CAMx data were referenced, implying use of data associated with multiple versions of the model (v6.50, v7.0beta6, v7.00, and v7.10)[23]. If multiple versions of CAMx were used and/or inputs, outputs, or tools designed for different versions of CAMx were leveraged, the modeling assessment would be inconsistent and results largely irrelevant. In another exchange among the modelers[24], it was noted that model outputs were copied and handled over multiple operating systems and that numerical noise in model outputs could be present and could contribute to variations in modeled concentrations. If that noise was on the order of a level of EPA's reference level of 0.01 ppb, any implications based on the modeling would be irrelevant.

[23] Readme files from data provided by EPA on external hard drive.
[24] Readme file from /work/ROMO/2016platform/CAMx_v7.10/2026fj_nonegusa_16j/12US2/postp_tools/makefinaltable/log/, as provided by EPA on external hard drive.

Any inference in the Proposed Rule as to the significance of BRS's NOx emissions relative to downwind Ozone concentrations at Brazoria is based on modeling that is largely incapable of predicting Brazoria Ozone variability, includes uncertainty from file management and model version issues, and is inconsequential.

3. ADDITIONAL MODELING DATA AND THE SIGNIFICANCE OF BRS

3.1 Air Parcel Trajectories Using HYSPLIT Have Been Historically and Recently Approved by EPA in Determination of Cross-State Ozone Transport Significance and Were Used in The Proposed Rule by EPA in Screening Assessments.

The National Oceanic and Atmospheric Administration (NOAA) Air Resources Laboratory's (ARL) Hybrid Single-Particle Lagrangian Integrated Trajectory model (HYSPLIT) is designed to evaluate air parcel trajectories, complex dispersion, and deposition simulations. HYSPLIT has evolved over more than 30 years and is one of the most extensively used atmospheric transport and dispersion models in the atmospheric sciences community.[25] HYSPLIT has been applied by regulatory agencies to perform back-trajectory analyses to evaluate the origin of air masses and establish source-receptor relationships. The EPA has recently relied on the State of Maine's HYSPLIT back-trajectory analyses, in conjunction with photochemical grid modeling, to approve Maine's request to remove a portion of the state from the Ozone Transport Region (OTR).[26] In addition, EPA used HYSPLIT trajectory modeling extensively in the Proposed Rule to evaluate Environmental Justice concerns related to coal-fired EGUs and perform screening assessments of emissions sources. Thus, HYSPLIT is a reputable and applicable model to screen long-range transport impacts, and EPA has shown this to be the case by approving its use as such in the past as well as using HYSPLIT in the Proposed Rule themselves. Were BRS to be a significant contributor to Ozone concentrations at Brazoria, HYSPLIT modeling would substantively corroborate EPA's extrapolations. If little corroboration exists, the finding of significance from EPA's extrapolations would be unsupported.

3.2 Based on Back-Trajectory Modeling, BRS Would Not Significantly Contribute to 2026 Maximum Ozone Events at Brazoria.

HYSPLIT was utilized to calculate seventy-two hour back-trajectories for the EPA's top-ten CAMx predicted maximum daily 8-hour (MDA8) 2026 ozone events for Brazoria as summarized in **Table 5**.

[25] Stein, A. F., R. R. Draxler, G. D. Rolph, B. J. B. Stunder, M. D. Cohen, and F. Ngan. "NOAA's HYSPLIT Atmospheric Transport and Dispersion Modeling System", Bulletin of the American Meteorological Society 96, 12 (2015): 2059-2077, accessed Oct 7, 2021, https://doi.org/10.1175/BAMS-D-14-00110.1

[26] 40 CFR Part 81 - *Response to Clean Air Act Section 176A Petition From Maine; Final Action on Petition*

Table 5: Top Ten Max Daily 8-hour Ozone Design Values at Brazoria, TX (2026)

Receptor	Average 8-hour Ozone Design Value (EPA's 2026fj Case; ppb)	Max 8-hour Ozone Design Value (EPA's 2026fj Case; ppb)	Month	Day	Top Ten Max Daily 8-hour Ozone Design Values (EPA's 2026fj Case; ppb)
Brazoria, TX, EPA Monitor #480391004	69.1	71.2	6	30	63.3
			6	6	61.6
			5	20	60.7
			6	8	59.8
			9	28	59.2
			9	11	58.2
			9	29	57.0
			5	18	56.6
			5	17	56.0
			5	6	55.8

Each HYSPLIT back-trajectory examined four starting heights above ground: 100-meters, 500-meters, 1000-meters, and 1500-meters. These heights include the expected levels within the atmospheric mixing layer, yet above the influence of local terrain, which EPA considers relevant in assessing the transport of air parcels for potential contributions to ozone concentrations at monitor locations.[27] Meteorological data files for the analysis were obtained from the NOAA ARL archive[28] and consist of the National Centers for Environmental Prediction (NCEP) North America Mesoscale (NAM) daily meteorological files, at a 12-km horizontal resolution. The start time for each back-trajectory analysis was set equal to the assumed starting hour of the predicted maximum eight-hour ozone value for each elevated ozone day, converted to Universal Time (+ 6 hours).

The results of the back-trajectory analyses indicated that the top three ozone days with greater than 60 ppb Ozone (highlighted in **Table 4**) had contributing air parcels originating well outside of, or only briefly passing through the very southern section of AR, as shown in **Figure 9** (> 60 ppb trajectories coded orange in the bottom map). For the remaining 7 days, a majority of the parcels also originated outside of AR (< 60

[27] EPA's *Responses to Significant Comments on the State and Tribal Designation Recommendations for the 2015 Ozone National Ambient Air Quality Standards (NAAQS)*, Docket Number EPA-HQ-OAR-2017-0548, April 2018.

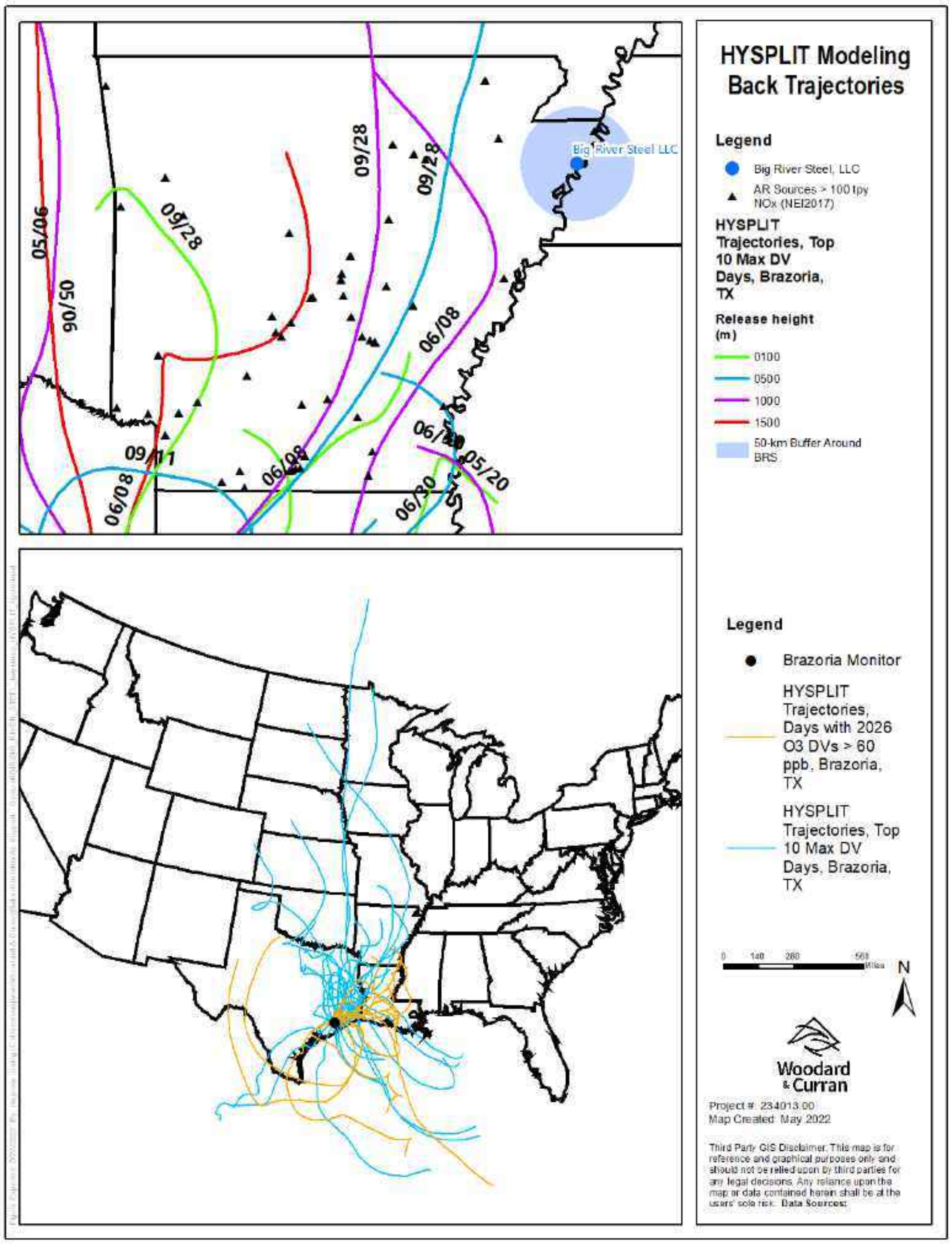
[28] NOAA Air Resources Laboratory Gridded Meteorological Data Archives. ftp.arl.noaa.gov/pub/archives; accessed May 2022.

ppb trajectories coded blue in the bottom map of **Figure 9**). For the parcels that did traverse through the state, the majority traveled through the central third of the state, and no parcel traveled within even 50 kilometers of BRS.

While back-trajectories offer a general assessment of source–receptor relationships and turbulent mixing processes can impact air parcels during transport, HYSPLIT back-trajectory analyses have utilized meteorological data at an equivalent horizontal resolution to EPA's CAMx modeling (12-km) and EPA has relied on HYSPLIT data to support other cross-state Ozone transport determinations. At the least, if BRS was significantly contributing to maximum Ozone events at Brazoria, HYSPLIT back-trajectory modeling should corroborate that finding of significance by multiple trajectories at multiple starting heights being near BRS. The additional modeling indicates that this is not the case. Additional modeling suggests that when Ozone events are maximum at Brazoria (e.g., > 60 ppb), parcels typically do not originate in AR in general. The HYSPLIT modeling suggests that when metrological flow in the region is such that NOx emissions in the northern portion of AR may contribute to Ozone concentration at Brazoria, those contributions are a portion of an overall concentration that is well below the 8-hour NAAQS (< 60 ppb) and thus would pose no significant threat to Brazoria attaining or maintaining the 8-hour Ozone NAAQS of 70 ppb. To the extent that any sources of NOx emissions in AR contribute significantly to Brazoria Ozone concentrations, those sources would be in the central and southern areas of AR, and not in the distant northeastern area where BRS is located. This additional modeling straightforwardly refutes the broadly determined finding of significance that EPA has placed on BRS's NOx emissions relative to Brazoria Ozone concentrations.

Any inference in the Proposed Rule as to the significance of BRS's NOx emissions relative to downwind Ozone concentrations at Brazoria is unsupported and uncorroborated by additional modeling and is inconsequential.

Figure 9: HYSPLIT Centerline Trajectories of Top Ten Max Daily 8-hour Ozone Design Values (2026) for Brazoria, TX

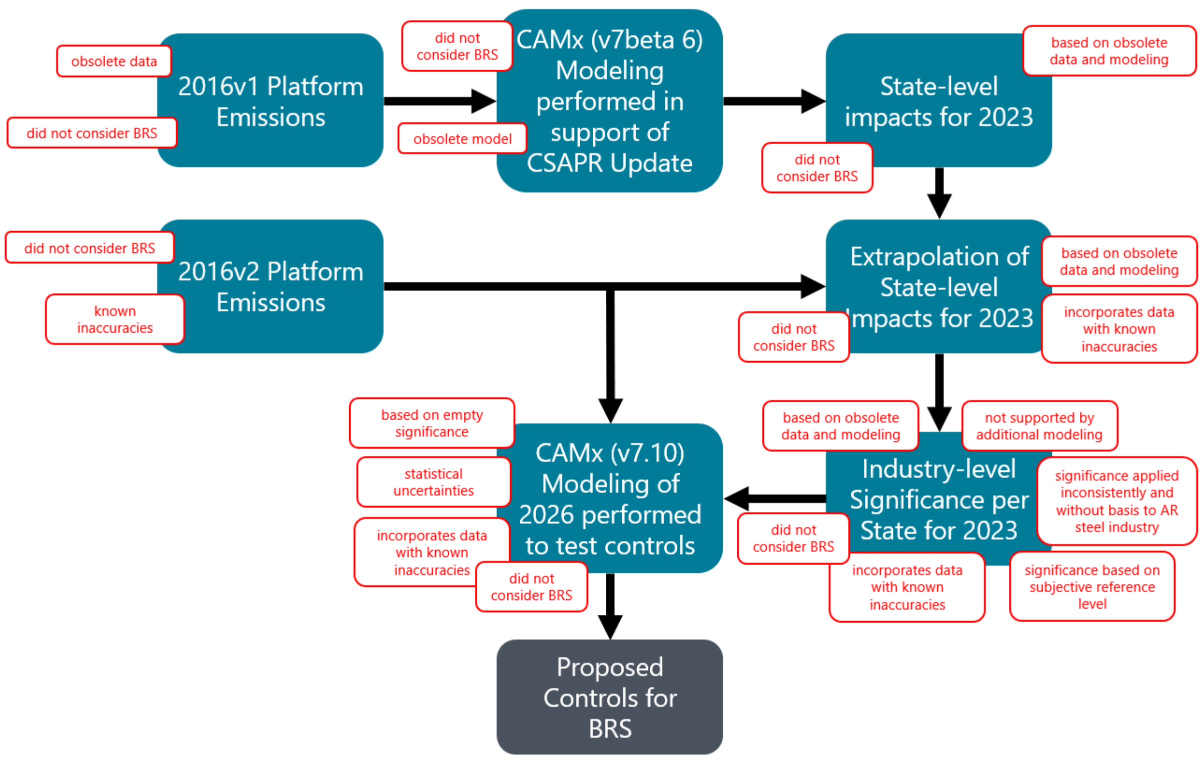


The authors gratefully acknowledge the NOAA Air Resources Laboratory (ARL) for the provision of the HYSPLIT transport and dispersion model and/or READY website (https://www.ready.noaa.gov) used in this memo.

4. CONCLUSION

Reiterating the schematic describing EPA's approach in **Figure 1** and updating with commentary resultant from the above discussion provides a representation of our findings and opinions (see **Figure 10**). At each step in the process that EPA applied, uncertainties and gaps of appropriateness and robustness were introduced. Based on our review and analysis, it is our opinion that _EPA's modeling in support of the Proposed Rule does not sufficiently demonstrate that NOx emissions from BRS significantly contribute to Ozone concentrations at the monitor in Brazoria County, Texas_.

Figure 10: Estimated Schematic of EPA's Approach to Determine Industry-level Significance – With Commentary



ATTACHMENT 1: UNDERSTANDING OF EPA'S EXTRAPOLATION APPROACH

Our understanding of EPA's extrapolation approach employed in the Proposed Rule to determine the contribution of a given amount of NOx emissions (E) is summarized below as a factor (f) which scales state-level model contributions (C) at a given receptor (R), multiplied by the emissions.

The contribution (C) of emissions, E, to Ozone concentrations at receptor, R can be expressed as Equation 1, where $C_{S,R}^{2023}$ is the state contribution at receptor R, for the 2023 inventory year.

$$C_{E,R} = E f_R C_{S,R}^{2023} \qquad \text{(Eq. 1)}$$

The receptor-level calibration factor in Eq. 1, f_R, is calculated as a ratio of changes in modeled contributions at receptor, R (Eq. 2). The ratio is a linear assumption to estimate how contributions at R would respond to emissions non-linearly due to model dynamics. The ratio compares how the model actually responds to emissions (the numerator in Eq. 2 – the difference between two modeled concentrations at R, year 2023 versus 2016) versus how the model would have responded to an increase in emissions (the denominator in Eq. 2 – the difference between a 2023 modeled concentration at R and a derived concentration at R for year 2016) if the modeled response to a change in emissions were linear.

$$f_R = \frac{C_R^{2016} - C_R^{2023}}{C_R^{2016*} - C_R^{2023}} \qquad \text{(Eq. 2)}$$

The derived 2016 concentration term in the denominator of Eq. 2 is EPA's "uncalibrated" concentration, C, at receptor, R = C_R^{2016*}. This term approximates what the concentration at R would be if the modeled concentration at R for year 2023 were adjusted upwards based on how much more emissions were present in 2016 relative to 2023 in each state. The uncalibrated "2016" concentration at R is the modeled 2023 concentration plus the sum of each state's uncalibrated concentration change at R.

$$C_R^{2016*} = C_R^{2023} + \textstyle\sum_S dC_{S,R}^{2016*} \qquad \text{(Eq. 3)}$$

The uncalibrated contribution change from state, S, at receptor, R = $dC_{S,R}^{2016*}$ is the result of scaling the modeled 2023 contribution from state S at receptor R by the fractional change in emissions within that state.

$$dC_{S,R}^{2016*} = C_{S,R}^{2023}\left(\frac{E_S^{2016} - E_S^{2023}}{E_S^{2023}}\right) \qquad \text{(Eq. 4)}$$

Where state-level emissions in state, S, for inventory year, Y = E_S^Y and the contribution of state, S, at receptor, R, for model year Y = $C_{S,R}^Y$.

In summary, EPA estimated the model response due to emissions changes of a complex multi-dimensional non-linear chemical transport model at a given receptor (R) by the algebraic application of linear factors (dC and f_R) to a state-level modeled contribution there ($C_{S,R}^{2023}$).

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN

ADDRESSING REGIONAL OZONE TRANSPORT FOR

THE 2015 8-HOUR NAAQS.

June 21, 2022

<u>EXHIBIT B:</u>

Black and Veatch

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B&V Project 412637
B&V File 14.2000
June 17, 2022

Attention: Martin T. Booher

Subject: Technical Feasibility of SCRs on Big River Steel's Electric Arc Furnaces

Introduction

The EPA has proposed new performance standards for electric arc furnaces (EAF) in the steel industry, issued on April 6, 2022, with a review and comment period to follow. The proposed rules are part of a proposed Federal Implementation Plan (FIP), issued under the "good neighbor" provisions of the Clean Air Act (CAA), which would establish new emission limits for multiple sources in order to limit the emissions of NO_X from states that significantly affect the ability of other downwind states to comply with the Ozone National Ambient Air Quality Standards (NAAQS). Per proposed 40 CFR 52.43(c), EAFs will be required to meet a NO_X emission limit of 0.15 lbm/ton steel on a 3-hour rolling average. The EPA based this limit on their consideration of baseline emissions and permit limits between 0.2 and 0.35 lbm/ton steel, and a minimum 40 percent reduction in NO_X emissions was assumed by adding a selective catalytic reduction (SCR) system on EAFs. Facilities are to meet these emission limits by the start of the ozone season (May 1) in 2026.

Big River Steel owns and operates a steel facility in Osceola, Arkansas, which includes two EAFs. An EAF is a metallurgical furnace that uses graphite electrodes to supply electrical energy. First, the furnace is charged with scrap metal, with the composition of the scrap metal based on the steel that is to be made. The electric energy will generate electric arcs in the furnace that melt the steel, and after melting is complete, the molten steel is refined to remove various impurities (e.g., phosphorous, sulfur, aluminum, silicon, manganese, etc.) by blowing oxygen through the molten steel. The system is operated as a batch process, alternating between melting, refining, and other steps such as de-slagging (tilting the furnace to pour slag through an opening), tapping (pouring the molten steel from the furnace), and turn-around (re-charging the furnace for the next batch of scrap metal). Therefore, the flue gas properties will vary significantly depending upon its stage of operations, making NO_X controls for EAFs difficult to implement.

The EAFs are the largest NO_X emitters at the facility (the only emission units permitted to emit more than 100 tons of NO_X per year) and produces other regulated emissions as well. Particulate matter is controlled by using a baghouse downstream of each EAF, which removes the particulate matter before exiting that baghouse's stack. Prior to entering the baghouse, the flue gas is cooled, because the flue gas temperatures from the EAF are beyond the operating temperature of all bags in regular commercial use. Prior to the baghouse, the cooled flue gas also goes through a spark arrestor to remove larger metal sparks and flammable debris that could otherwise compromise the baghouse. The proposed ruling by the EPA impacts the current EAFs, as well as a planned second facility which started construction earlier this year and will also include two EAFs.

Current Emissions

Big River Steel conducts routine stack tests on the emissions from their EAF, and over the last several years, NO_X emissions have averaged around 6.7 ppm, with a maximum recorded value of 12.6 in 2021 and a lowest recorded value of 4.7 in 2019. Converting the emissions to lbm/ton of steel, the NO_X emission average was about 0.20 lbm/ton, with a high of about 0.29 lbm/ton and low of 0.15 lbm/ton. These emission tests were hour-long tests, with an average value derived from three tests. Based on the average values, the emissions from the EAF would need to be reduced by 23 percent, and based on the maximum test value, the reduction would need to be near 49 percent. Since the emissions cannot be surpassed, reduction technologies like an SCR would need to remove sufficient NO_x from the maximum emissions to a margin below the limit, and 49 percent would be the minimum removal efficiency required.

Selective Catalytic Reduction

Technical Background
SCR systems are a post-combustion NO_X control technology for achieving reductions in NO_X emissions which have been primarily utilized in utility coal boilers. In SCR systems, vaporized ammonia (NH_3) is injected into the flue gas stream, acting as a reducing agent, with a set of one to four (typ.) catalyst banks helping to facilitate the reaction. Some utility boiler SCR installations have been able to lower NO_X emissions by greater than 90 percent, but this is contingent on the unit's operating characteristics, such as flue gas and fly ash composition, as well as the fuel that is being burned.

The primary chemical reactions between NO_X and NH_3 are demonstrated by the following equations:

$$2NO + 2NH_3 + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

$$N0_2 + 2NH_3 + \frac{1}{2}O_2 \rightarrow \frac{3}{2}N_2 + 3H_2O$$

$$NO + N0_2 + 2NH_3 \rightarrow 2N_2 + 3H_2O$$

The reactions shown above can occur spontaneously at temperatures above 1600 °F, but at lower temperatures these reactions need a catalyst to promote their reactions. Temperatures are still an important consideration even with SCRs, as most SCRs operate in a temperature range of 550 to 900 °F. There have been catalysts installed at lower and higher temperatures; however, there are critical design conditions that a flue gas must meet in order for such a catalyst to work effectively and with consistent performance. At low temperatures, the presence of sulfur and other chemicals can poison the catalyst (permanently rendering it less effective or even ineffective), and temperatures will still need to be maintained above a minimum of approximately 400 °F. At higher temperatures (up to 1,000 to 1,100 °F), stainless steels, titanium, or other expensive materials are needed to withstand the higher temperatures, and higher volumes would be required to achieve similar NO_X reduction rates. NH_3 also will oxidize to NO_X at higher temperatures, so ammonia slip (unreacted ammonia emissions) will need to be tightly controlled to prevent unintentional NO_X production.

The reaction mechanisms between NO_X and NH_3 are very efficient, with a reagent stoichiometry of approximately 1.05 (molar ratio of NH_3/NO_X removed). A simplified schematic diagram of a typical SCR reactor for the utility industry is illustrated in Figure 1. However, due to increasingly stringent NO_X emissions regulations most modern SCR systems are built without bypass systems. SCR cleaning on modern systems is typically done by sonic horns, rather than steam or air sootblowers.

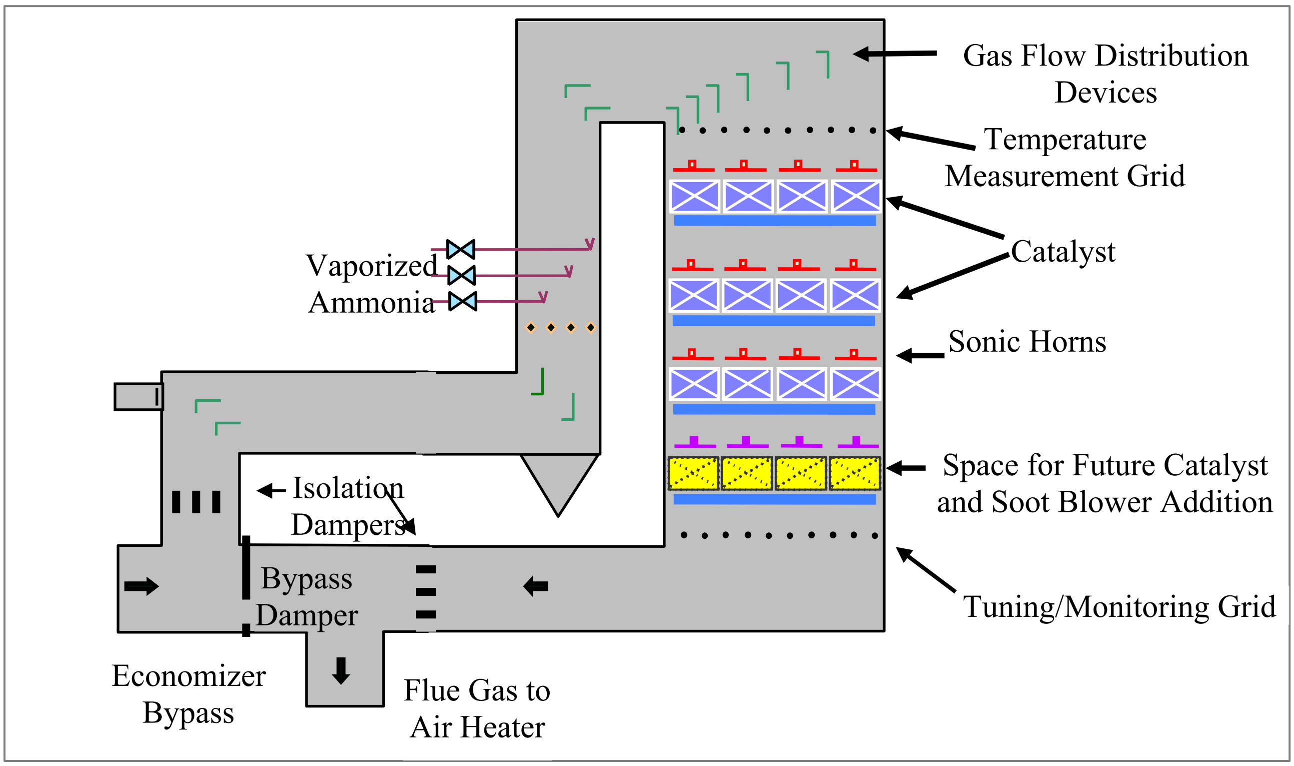

Figure 1 ***Schematic Diagram of Typical Utility Industry SCR Reactor***

The SCR reactor is the housing for the catalyst and is essentially a widened section of ductwork modified by the addition of gas flow distribution devices (turning vanes and dampers), steel grating to catch over-sized particulates, the catalyst and its support structures, access doors, and soot blowers. An ammonia injection grid is located upstream of the SCR reactor. The ammonia reagent for the SCR systems can be supplied by anhydrous ammonia, aqueous ammonia, or by conversion of urea to ammonia. Since the ammonia is vaporized prior to contact with the catalyst, the selection of ammonia type does not influence the catalyst performance. However, the selection of ammonia type does affect all other subsystem components, including reagent storage, vaporization, injection control, and balance-of-plant requirements (including potential use of auxiliary power and/or process steam in many systems).

SCR systems have a variety of interfacing system requirements to support operations. These impacts predominately relate to the flue gas draft, auxiliary power, gas temperature, controls, ductwork, and reactor footprint. Depending upon the arrangement and performance requirements, flue gas draft losses can range from 4 to 10 in. w.g. This can be compensated with the addition of induced draft (ID) booster fans. Draft losses may influence the selection and design of the ductwork, and as a result, possible structural reinforcements may need to be considered. In conjunction with fan additions or modifications, an upgrade of the auxiliary power system might be necessary, which might also be triggered by ammonia supply system requirements.

Technical Infeasibility for Deployment of SCR Systems with EAFs
The EPA has used the term "technical feasibility" in multiple proposed and promulgated rulings. This term has required clarity over the years, as it is critical to determining whether a control technology is to be implemented at a particular facility. An example of when the EPA defined this term was in the proposed ruling for "State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental," (proposed April 28, 1992) where "Technological Feasibility was discussed. In Appendix C4 of the proposed ruling, the feasibility of a technology, "should consider the source's process and operating procedures, raw materials, physical plant layout, and any other environmental impacts…"

Technical feasibility is further defined in other promulgated rulings. Drawing from the best available retrofit technology (BART) guidelines (40 CFR Part 51, Appendix Y, Section IV.D.2) as general guidance, this entails determining whether technical difficulties would preclude the successful use of the control option on the emitting unit under review based on physical, chemical, or engineering principles. As described in 40 CFR Part 51, Appendix Y, Section IV.D.2.:

> "Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: 'availability' and 'applicability.'… a technology is considered 'available' if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration."

The EPA "does not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as 'available' for purposes of BART review." (40 CFR Part 51, Appendix Y, Section IV.D.2.2)

Based on these definitions of technical feasibility, installing an SCR after Big River Steel's EAF as it currently exists (i.e., no modifications to the process) is technically infeasible. The reasons for this determination are as follows:

1) Black & Veatch and Big River Steel are not aware of an SCR that has been installed at another EAF (e.g., Black & Veatch has not worked on an SCR project on an EAF, and Black & Veatch's and Big River Steel's research did not unearth any SCR installations on EAFs). Black & Veatch has contacted Andritz, a leading SCR provider, and they have stated they do not have an SCR installed on any EAFs. Andritz has acquired Alstom/GE's air quality control business, so their statement includes Alstom/GE's experience.

2) To the EPA's statement regarding whether a "technology could be applied to the source under review," an SCR could not be currently installed at Big River Steel's EAF because of catalyst limitations with flue gas temperatures. Black & Veatch contacted catalyst suppliers, and two (CERAM and Cormetech) have responded that they do not have any catalysts installed at the temperature ranges present at Big River Steel (other contacted vendors have not responded at this juncture). The EAF's flue gas temperatures fluctuate significantly depending on its mode of operation, with a maximum flue gas temperature greater than 1,200 °F prior to the baghouse (which is subsequently cooled to near 200 °F in order to protect the bags). Neither temperature range fits the design requirements of existing SCR catalysts.

   Black & Veatch has also conducted a literature search for low-temperature catalysts, and none could be found that operate at the temperatures found at Big River Steel's EAF. Even if one were found, it would need to be proven at an industrial scale to be considered applicable for Big River Steel. The lack of findings from the literature review corroborates Black & Veatch's discussions with vendors.

<u>Required Modifications to Install an SCR</u>
The finding that it is not technically feasible to employ an SCR at Big River Steel is further supported by the substantial modifications that would be necessary to attempt to address the flue gas temperature and composition concerns, something that (as discussed above) has not to our knowledge been accomplished anywhere in the world.

Should such an installation be attempted, there are many changes required in order to allow successful, consistent, and reliable operation at the EAF. These include changes related to the flue gas temperatures from the EAF, as well as other possible changes

Flue Gas Cooling
Flue gas cooling is currently being done at site. The flue gas is sprayed with water prior to the spark arrestors, which are located upstream of the baghouse. The flue gas is cooled to protect the bags from burning upon processing the EAF's hot flue gas temperatures. However, the spray water cools the flue gas to around 200 °F in order to protect the bags in the baghouse, which is much too low for an SCR to operate. Low-temperature catalysts also cannot be installed in flue gas streams with sulfur and other potential poisons, and installing an SCR upstream of the baghouse exposes the SCR to all of the particulate matter from the EAF. The particulate matter from the EAF has a high level of sodium and potassium, both of which are known to be harmful to catalysts. As a result, there are serious concerns with the feasibility of installing an SCR, needless to say a low-temperature catalyst, upstream of the baghouse.

Cooling the flue gas between the EAF and the existing cooling system was also investigated, despite the potential hurdles with the particulate matter content of the flue gas. The temperature profile leaving the EAF is shown in Figure 2. The data is from February 1, 2022, but it is typical of most operating days at the facility. The temperatures reach a maximum of 1,298 °F, so a cooling system will need to lower the flue gas temperature from 1,200-1,300 °F down to 550°F.

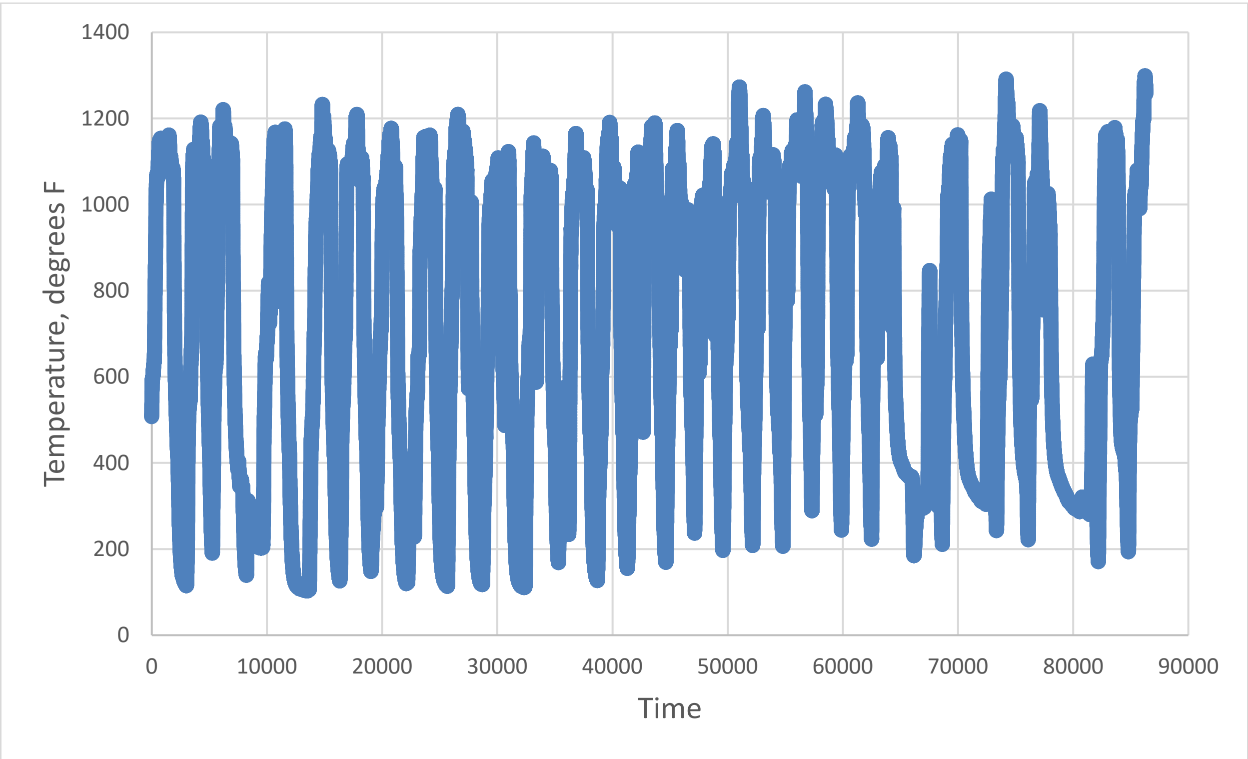

Figure 2 ***Temperature of Flue Gas Exiting EAF and Upstream of Spray Water Cooling***

Figure 2 also shows that the temperature significantly swings throughout the day, which is sensible based on the EAF's batch operations. These temperature swings present a potential problem with installing an SCR upstream of the baghouse, as the SCR catalyst and housing need to be at the necessary operating temperatures along with the flue gas. If the SCR catalyst is lower than the minimum temperature of the SCR, then de-NO_X reactions would occur at a much lower rate, if at all, even if the flue gas is well above the minimum temperature. In most SCR installations (steady state processes, not batch), there is a period of time (e.g., startup) where the SCR will warm up to the necessary temperature. If an SCR were to be installed upstream of the baghouse, then barring extensive insulation or some other method of heat retention or pre-heating with external heat sources, it's possible that the SCR steel and catalyst will cool down below the minimum temperatures between the temperature peaks. A more thorough analysis (e.g., thermal model of a potential SCR on the EAF, bench/pilot scale testing of how quickly an SCR picks up and dissipates heat, literature research on available data on the topic, etc.) is required to determine how the SCR's temperature will behave with such large variations in the flue gas temperatures, whether such reactions may prevent the SCR de-NOx reactions from occurring at a sufficient rate above that needed to comply with the 49% control efficiency required based on the above estimates, and if needed, what mitigating steps are required, and whether any such mitigating steps are feasible. This question of how the catalyst design and steel will be impacted by the temperature swings of the EAF would require a detailed engineering study that was not possible to complete during the 2.5 month comment period in this rulemaking.

Beyond simply the issue with the oscillating flue gas temperatures, cooling flue gas from 1,200-1,300 °F can typically be accomplished by two readily available methods. The first is using ambient air to temper the flue gas temperature. In this option, ambient air is drawn through filters by a blower and sent into the ductwork to mix with the flue gas and lower its temperature. This has been implemented in many combustion turbine (CT) installations that were required to have an SCR. CT exhaust temperatures are commonly around 1,000 °F and above, so tempering air has been used to lower the temperature down to around 900 °F or lower (the EAF will require more tempering air due to needing to lower flue gas temperatures by a greater degree). This additional volume of tempering air must pass through the existing baghouse, ID fan, and stack. The sizing of each of these components would need to be reviewed to ensure sufficient capacity is available (e.g., whether the ID fan support the additional pressure drop created by the SCR and the additional tempering air passing through the ductwork and baghouse); otherwise, modifications to these systems would be needed. This question, too, would require a detailed facility-specific engineering study that was not possible to complete during the 2.5 month comment period in this rulemaking.

The second option is to inject water into the flue gas, whereby the latent heat of evaporation of the water will absorb heat away from the flue gas. This process is already done at site, but since the target temperature for cooling the flue gas for the SCR is different than for protecting the bags, the existing system cannot be used for both purposes. As a result, two separate flue gas cooling systems would be required, which would not only require increased complexity, but it would require sufficient space for the residence time required for evaporation of the water vapor. This would require additional installation space, which currently does not exist.

Flue Gas Heating
Multiple options are possible for heating the flue gas from 200 °F to 550 °F downstream of the baghouse. One is to use a natural-gas fired duct burner. Duct burners have been installed in numerous facilities for increasing flue gas temperatures, most notably before heat recovery steam generators (HRSG). Utilizing natural gas combustion to heat the flue gas also introduces an additional emissions source (particularly of NO_x), which must be addressed in the facility air permit and may trigger additional permitting reviews. The flue gas temperature can also be increased by using electric or steam coils. This also would require detailed facility specific engineering not possible to complete during the 2.5 month comment period in this rulemaking.

Babcock Power provides an SCR for tail-end applications, where they direct flue gas through a regenerative thermal oxidizer (RTO), which is a large ceramic bed that can absorb and release heat. The flue gas would then pass through the first layer of an SCR and after that, it would be heated by a duct burner and pass through a second layer of catalyst. After the second layer, it will pass through another RTO, this time transferring heat into the second RTO. Once the first RTO's heat has dissipated, the cycle is reversed so flue gas passes through the second RTO before passing through the catalyst. Babcock Power's process is termed a Regenerative SCR (SCR), and it is typically more expensive than a traditional SCR due to the additional components.

Cost Estimates
Black & Veatch has been employed on many projects and studies over the years with power-related equipment and air quality controls. From these experiences, high-level cost estimates were calculated for implementing heating and cooling options for the flue gas. These past projects were based on design conditions from past clients, cost quotes from vendors, and engineering design specifications developed by Black & Veatch. These are not included in EPA's Control Cost Manual, as these would be unique to this particular application for EAFs. These estimates are not budgetary in nature, as more time and effort would be required for that level of accuracy, but rather, these estimates are provided to give a general idea of the additional costs that would be incurred to install an SCR. A facility specific detailed engineering design would be required in order to develop more precise cost estimates. Table 1 summarizes the cost estimates for each EAF for adding a tempering air, spray water system, and duct burner to the Big River Steel EAF. Other options for heating the flue gas were not considered, because duct burners are the simplest option for attempting to address the incompatibility of Big River Steel's EAF options and SCR.

Table 1 Cost Estimate Summary for Flue Gas Temperature Control Options

Option	Equipment Cost	Installed Cost
Tempering Air	$7,250,000	$11,700,000
Spray Water System	$7,400,000	$11,200,000
Duct Burners	$20,000,000	$27,800,000

The above costs include nominal ductwork and piping due to the fact that most studies serving as the cost estimates' basis were greenfield sites. The layout of Big River Steel's facility would increase the costs for these items due to its size and complexity (although the amount of increase is not known at this juncture). The EAF is a large structure, and the platforms that fans and pumps would be located are far away from the flue gas ductwork.

Other Considerations for Installing an SCR
In addition to the flue gas temperature concerns, there are other potential challenges that must be confirmed before an SCR can be installed. A common theme to these issues is the custom design of Big River Steel's facility. When the facility was designed and commissioned, the inclusion of a substantial new emission control system like SCR was not accounted for in the design, so the installed equipment will have challenges in accommodating an SCR. These include:

1) Flue gas passing through an SCR will experience a pressure drop due to flow resistance from passing through the SCR's catalyst and additional ductwork. The pressure drop should be around 4 inches w.g. (but could be larger). It is common on SCR retrofits for a booster fan to be added to the system's draft system, or the existing ID fans can be retipped to increase their capacity, to overcome this additional pressure drop. Further evaluation of the draft system and fans is required, but at this time, it is believed that a new booster fan will be required.

   Even if the existing draft fans were capable of providing the additional pressure drop, the auxiliary electrical system may not be able to support the additional power required by the fans.

The installed auxiliary electrical system does not have much additional capacity, and further analysis is required to confirm the amount of new cabling, transformers, etc. that will be required to even attempt providing the additional power needed. This also would require detailed facility specific engineering not possible to complete during the 2.5 month comment period in this rulemaking.

2) There is limited operational space at Big River Steel's facility, particularly around the EAF. The EAF is within a large structure that is highly congested with equipment, piping, and ductwork, and little space is available for installing a tempering air skid, ammonia handling system, and ammonia pump skid. The location for the SCR itself will also require more analysis. The ductwork between the EAF and the baghouse goes over a major road at the facility that is accessed by large haul trucks that require significant clearance levels. Accordingly, any attempt to employ an SCR upstream of the baghouse would have to be elevated with a steel support system that does not interfere with the roads. Assuming such a configuration can be accomplished, it would increase the installation cost significantly (these challenges were not accounted for in the cost estimates in Table 1).

   At the back-end of the baghouse there is only about 12.5 feet of space between the baghouse and the stack, and the ID fan is located adjacent to the stack. Even if it's possible to tie in the SCR's inlet duct between the baghouse and stack, but 12.5 feet may be too narrow for tying in the SCR's outlet duct at the same location. The outlet duct's tie-in point would need to return to the system upstream of the ID fan, which could require a stack breeching and other considerations. This also would require detailed facility specific engineering not possible to complete during the 2.5 month comment period in this rulemaking.

   Barring substantial modifications to the plant flue gas system, there is no appropriate location to site a booster fan. As there is no room between the ID fan and the stack, as the two are adjacent to one another, any booster fan would need to be located off to the side of the baghouse or behind the stack. The ductwork tying in the booster fan would therefore require multiple turns that would increase the pressure drop it needs to provide.

   As a result, there is no appropriate location where SCR can be guaranteed to be feasibly installed. Further analysis is required to determine where an SCR and other supporting equipment could feasibly be located, if at all.

3) The particulate matter produced by the EAF was analyzed for potential catalyst poisons, as there is significant concern regarding alkali metals that have been known to poison SCR catalysts. One prominent example is an SCR installation at Coyote Station in North Dakota. North Dakota lignite is burned at the facility, and it is known to have elevated levels of sodium. At Coyote Station, the SCR experienced detrimental plugging issues due to the sodium in the flue gas. Potassium-based poisoning is well-known throughout the power industry, especially for the case of power stations that have attempted to co-fire significant amounts of high-potassium biomass fuel.

The particulate matter from the EAF captured by the baghouse has potassium and sodium levels of 11,500 and 8,080 ppm, respectively. These tested levels for potassium and sodium appear to be high, but the dust concentration is not as large compared to coal-fired power plants. Black & Veatch has contacted catalyst suppliers for their advice regarding use with these high potassium and sodium concentration levels, but no conclusions have been attained at this time. Further analysis is required to determine the effects of the particulates' composition on catalysts.

4) Ammonia slip is a consideration for SCR design, with more catalyst being typically required to achieve lower ammonia slip. Ammonia slip is often increased by swings in flue gas temperatures, variations in the flue gas flow rate, the level of catalyst poisoning, the amount of wear and pluggage in the ammonia injection grids, etc. The potential for ammonia slip will need to be confirmed through the permitting and regulatory process.

Other NO_X Reduction Options:

The EPA proposed ruling is based on deploying an SCR, but as summarized in this memo, there are multiple issues with implementing an SCR at Big River Steel's EAF. The proposed limit is not restricted to being met solely by an SCR, so some consideration should be given to whether alternative control options would be able to meet the proposed limits.

NO_X control methods can be generally categorized into two groups for typical utility boiler applications, pre-combustion and post-combustion. Pre-combustion refers to ways to control the formation of NO_X. NO_X is primarily created when nitrogen in the air is combusted. Nitrogen in fuels, or in this case scrap metal, can also be combusted to create NO_X, but the rate of NO_X from fuels is minor compared to NO_X from the air. Sensibly, one of the ways to reduce NO_X formation is to lower the flame temperatures. For traditional furnaces, this is accomplished by using low-NO_X burners (LNBs) that control the mixing of fuel and air in a pattern designed to minimize flame temperatures. However, melting scrap metal in the EAF is primarily driven by electricity rather than by a flame or combustion of fuel, so LNBs cannot be relied on for further reductions. Neither are other pre-combustion methods, such as over-fire air (OFA), due to the lack of combustion. Further analysis is required to determine if there are ways to optimize the electric arcs in the EAF to minimize NO_X formation, but since the electric arcs are integral to melting scrap metal, there is doubt as to whether this can be accomplished.

Post-combustion control methods refer to ways to remove NO_X after it has been generated. SCRs are the most common post-combustion control method in some other industries for achieving significant levels of NO_X reduction, but when the reduction levels are less demanding, selective non-catalytic reduction (SNCR) systems are an option. SNCR systems inject urea solutions into furnaces where the temperature is optimal for NO_X and NH_3 reactions. However, the flue gas temperature at the EAF outlet varies too greatly and is too low for SNCR to be implemented. An SNCR system will typically require temperatures to be consistently greater than 1,550 °F in order to provide NO_X reductions. Black & Veatch confirmed with Fuel Tech, a leading provider of SNCR systems, that an SNCR is not practical for EAFs, and that they have not installed an SNCR at any EAF.

Conclusion:

Based on Black &Veatch's experience, research, and discussions with suppliers, installing an SCR at Big River Steel's EAFs is technically infeasible without making major modifications to the system, and it is unknown whether the EPA has considered the cost of these major modifications in their proposed ruling. Even if these modifications were made, there are potential challenges to installing and successfully operating an SCR that will need detailed facility specific engineering investigation. Black & Veatch would be happy to assist Baker Hostetler in providing Big River Steel further support as needed on this issue, as well as any other issues that arise.

Very truly yours,

Black & Veatch Corporation

Paul Lee
Black & Veatch

cc: Martin Booher – Baker Hostetler Law
Josh Wilson – Baker Hostetler Law
Steve Frey – Community of Practice Leader Air Services
Una Nowling – Black & Veatch Project Manager

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN

ADDRESSING REGIONAL OZONE TRANSPORT FOR

THE 2015 8-HOUR NAAQS.

June 21, 2022

<u>EXHIBIT C:</u>

Barr

COMMENTS TO THE

UNITED STATES STEEL CORPORATION

Regarding the

Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard

87 Fed. Reg. 87,66 (April 6, 2022)

Docket ID No. EPA-HQ-OAR-2021-0668

June 21, 2022

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LIST OF TABLES

Included herein are technical comments from Barr Engineering Co. ("Barr") in response to the U.S. Environmental Protection Agency's ("EPA" or "the Agency") *Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard; Proposed rule*, 87 Fed. Reg. 87,66 (April 6, 2022) ("Proposed Rule"), based on review of the Proposed Rule and its supporting technical documentation.

I. Taconite Iron Ore Processing Industry should be Excluded from the Proposed Rule Applicability since it is not part of the Iron and Steel Mills and Ferroalloy Industry

A. EPA's Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard should exclude the Taconite Iron Ore Processing Industry from the final rule for the following reasons and relevant supporting documentation:

1. The Taconite Iron Ore Processing Industry is not part of the Iron and Steel Mills and Ferroalloy Industry, as defined by the Taconite Iron Ore Processing Industry 4-digit NAICS codes and by the definition under 40 CFR 63. The NAICS description of Iron and Steel Mills and Ferroalloy Manufacturing corresponds to a NAICS code of 3311 and the NAICS description of Metal Ore Mining corresponds to a NAICS code of 2122. The Taconite Iron Ore Processing Industry (NAICS code 212210) is a subset of the Metal Ore Mining Industry.
2. Throughout the Proposed Rule, EPA refers to the '*seven non-EGU industries that provide opportunities for NOx emissions reductions that result in <u>meaningful impacts</u> on air quality at the downwind receptors*.' The seven industries identified by EPA in the "Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026" ("Non-EGU Screening Assessment memorandum") (EPA-HQ-OAR-2021-0668-0150) are shown in the below table.

Tier 1 Industries		Tier 2 Industries	
NAICS Description	NAICS Code	NAICS Description	NAICS Code
Pipeline Transportation of Natural Gas	4862	Basic Chemical Manufacturing	3251
Cement and Concrete Product Manufacturing	3273	Petroleum and Coal Products Manufacturing	3241
Iron and Steel Mills and Ferroalloy Manufacturing	3311	Pulp, Paper, and Paperboard Mills	3221

Glass and Glass Product Manufacturing	3272		

3. In the "Non-EGU Screening Assessment", the Metal Ore Mining Industry (4-digit NAICS 2122) was originally included as a Tier 2 facility; however, in a later step in the analysis EPA refined the Tier 2 grouping by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers, using the projected 2023 emissions inventory in the linked upwind states, which subsequently removed the Metal Ore Mining industry from the Tier 2 grouping as this industry was found to not have any "potentially impactful boilers" (See Table 1: Number of Emissions Unit Types in Tier 2 Industries in the Non-EGU Screening Assessment). Based on EPA's own assessment, boilers in the Metal Ore Mining industry, which would include the Taconite Iron Ore Processing facilities, do not provide opportunities for NOx emissions reductions that result in meaningful impacts on air quality at downwind receptors.
4. NOx emissions from taconite production kilns/indurating furnaces are already well controlled and regulated by the Minnesota Taconite Regional Haze BART FIP 81 FR 21671 (April 12, 2016), as amended most recently for Minntac on March 2, 2021 (86 Fed. Reg. 12095, codified at 40 CFR 52.1235). Because the industry is already well controlled and because EPA and the regulated community have already invested significant amounts of resources in determining appropriate NOx limits for indurating furnaces, it is unnecessary and inappropriate for EPA to now impose additional requirements to the industry.
5. In Section VII.C.3 of the Proposed Rule (20148), EPA states:

"The EPA did not find large boilers within the Lime and Gypsum Product Manufacturing (NAICS code 3274xx) or the Metal Ore Mining industries (NAICS code 2122xx). As such the EPA is not expressly proposing to include boilers in those industries. However, if as a result of receiving additional information during the comment period the EPA identifies large boilers within these two industries that meet the applicability criteria described below, those boilers could be subject to the requirements of the final rule."

Since no 'potentially impactful boilers' were identified from the Metal Ore Mining industry as part of EPA's "Non-EGU Screening Assessment" it is still not a 'potentially impactful boiler' because it would have been originally included in EPA's "Non-EGU Screening Assessment" and therefore should be removed from reference in the rule.

B. Discrepancies in the Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 ("Non-EGU Screening Assessment memorandum") warrant further quality assurance and explanation.

1. (EPA-HQ-OAR-2021-0668-0150), a supporting document to EPA's RIA, presents the analytical framework EPA used to "facilitate decisions about industries, emissions unit types, and cost thresholds for including emissions units in the non-electric generating unit 'sector' (non-EGUs)" and "summarizes the screening assessment the EPA prepared to identify industries

and emissions unit types to include in the proposed rule to obtain NOx emission reductions from non-EGUs."

To analyze non-EGU emissions units, EPA aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICs, focused on assessing emission units that emit >100 tpy of NOx. The focus was limited to potentially controllable emissions, and well-controlled sources that still emit >100 tpy were excluded from consideration. EPA then grouped the industries into Tier 1 and Tier 2 categories, as defined above.

Originally, Metal Ore Mining (4-digit NAICS 2122) was included in the Tier 2 grouping; however, in a later step EPA refined the Tier 2 grouping by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers, using the projected 2023 emissions inventory in the linked upwind states, which subsequently removed the Metal Ore Mining industry from the Tier 2 grouping. Based on EPA's own assessment, boilers in the Metal Ore Mining industry, which would include the MN taconite facilities, do not provide opportunities for NOx emissions reductions that result in meaningful impacts on air quality at the downwind receptors. Accordingly, application of the Proposed Rule to Taconite facilities is not supported by the underlying modeling because (1) the taconite facilities are not part of the Iron and Steel Mills and Ferroalloy Manufacturing Industry and (2) the Metal Ore Mining industry was removed from consideration in EPA's screening assessment.

Furthermore, boilers at taconite facilities that emit or have the potential to emit >100 tpy of NOx are not expressly listed under the text of the Proposed Rule as an "Affected Unit" (unlike a "taconite production kiln"). Instead, section 52.43 with respect to boilers only includes "industrial boiler" "at an iron and steel mill or ferroalloy manufacturing facility." Because taconite production is not in fact within the iron and steel mill or ferroalloy NAICS, it is unclear whether boilers at taconite facilities that emit or have the potential to emit >100 tpy of NOx are subject to the Proposed Rule as currently drafted. And in any case the underlying modeling cannot support application of the Proposed Rule to such boilers because boilers in the Metal Ore Mining industry were removed from consideration in EPA's screening assessment.

C. Inconsistencies with Iron and Steel Mills and Ferroalloy Manufacturing Industry 30-day rolling average vs. 3-hour rolling average for Gas-Fired Industrial Boilers require updating.

1. VII.C.3 states "In determining the averaging times for the limits, EPA initially reviewed the NESHAP for Iron and Steel Foundries codified at 40 CFR part 63 subpart EEEEE, the NESHAP for Integrated Iron and Steel manufacturing facilities codified at 40 CFR part 63 subpart FFFFF, the NESHAP for Ferroalloys Production: Ferromanganese and Silicomanganese codified at 40 CFR part 63 subpart XXX, and the NESHAP for Ferroalloys Production Facilities codified at 40 CFR part 63 subpart YYYYYY. EPA also reviewed various RACT NOX rules from states located within the OTR, several of which have chosen to implement OTC model rules and recommendations. Based on this information, the ***EPA is proposing to require a 30-operating day rolling average period as the averaging time frame for this particular industry***. The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short

term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production." (20145)

VII.C.5.c for Gas-Fired Industrial Boilers states "The proposed NOx emissions limits for gas-fired boilers subject to the requirements of this section is 0.08 lbs/mmBtu. The ***proposed averaging time for these emissions limits is a 30-day rolling average***. Additionally, EPA seeks comment on whether the EPA should establish less stringent emissions rates for boilers with low utilization rates, and if so, the appropriate emissions rate(s) and corresponding boiler utilization rate(s)." (20149)

§52.43(c) – "*Emissions Limitations and Requirements.* Beginning with the 2026 ozone season and in each ozone season thereafter, the ***emissions limitations in the following table must be met on a 3-hour rolling average***." (20181) Note: this is the only mention in the proposed FIP of a 3-hour rolling average.

There is inconsistency between the averaging time for the gas-fired industrial boiler emissions limits. Sections VII.C.3 and VII.C.5.c specify a 30-day rolling average and §52.43(c) specifies a 3-hour rolling average.

Boilers in the Tier 2 industries are also subject to a 30-day rolling average period as specified at §52.45(d)(2) & (e)(5), thus it would be inconsistent with the rest of the Proposed Rule not to use a 30-day rolling average period for boilers in the iron steel and ferroalloy industry (and taconite boilers if covered under that section). Additionally, there is no justification offered in the Proposed Rule or its supporting documents for a 3-hour averaging period.

D. A 3-hour Rolling Average Standard is Unsupported by Real-Time Ozone Transport Cross-State.

1. The rule is designed to address pollutant transport during the ozone season and any 1-hour, 3-hour, or even 24-hour restrictions are not necessary. Ozone transport across multiple states (or even a single state) would not be responsive to this type of short duration when emissions occur. The transport times can be days from sources to downwind receptors and vary considerably. The justification for a 3-hour rolling average does not exist. Short term averages are typically applied when there is a direct response between the downwind concentration and the emissions. For example, a 24-hour limit on a facility that is evaluating the 24-hour PM10 standard at its property boundary (i.e., much more direct cause and effect) matches the form of the standard with the source emissions limit. This type of short-term limit is not being discussed as part of the ozone transport FIP and shouldn't be.

2. The other limitations from the rule all include a 30-day rolling average. While this is better, EPA should clarify that monitoring recordkeeping and reporting are only required during the ozone season since the Proposed Rule's limits only apply during the ozone season. The use of a 30-day rolling average during the winter months is completely unnecessary as ozone concentrations are not elevated outside the ozone season (traditionally May – September) in many areas. EPA's proposal is an excessive limitation beyond the scope of the ozone transport

issues that they believe they are trying to resolve. If EPA moves forward with controls in Minnesota, it is Barr's recommendation that an ozone season total emission limit is the appropriate form and not an on-going 30-day rolling limit. This is consistent with the NOx transport rule and CSAPR, along with the other ozone transport state rules/SIPs designed to address ozone transport.

EPA's own statement applies good logic about using a longer average notwithstanding the ozone season issue discussed above - **"**The EPA finds that a 30-operating day rolling average period provides a reasonable balance between short term (hourly or daily) and long term (annual) averaging periods, while being flexible and responsive to fluctuations in operations and production."

II. EPA's Technical Modeling Analysis Justifying the Inclusion of Non-EGU Taconite Sources.

A. Is EPA's modeling approach for identifying upwind states to include in their future ozone attainment regional scale modeling and source type category contributions justified?

1. *EPA should reconsider the 1% (0.71ppb) threshold for identifying a state's contributions "significant" to a future modeled ozone NAAQS non-attainment downwind receptor. The August 2018 memo provided a reasonable argument for adjusting the significant level to 1 ppb.*

EPA's reasoning for retaining the 1% NAAQS threshold for the latest revisions to the Good Neighbor Rule makes it seem like adjusting the threshold will throw mass confusion into the entire process and make it unfairly apply tighter restrictions to some states and not others. To quote their own defense

> "Where alternative thresholds for purposes of Step 2 may be "similar" in terms of capturing the relative amount of upwind contribution (as described in the August 2018 memorandum), nonetheless, use of an alternative threshold would allow certain states to avoid further evaluation of potential emissions controls while other states must proceed to a Step 3 analysis. This can create significant equity and consistency problems among states."

This argument contradicts itself by assuming that the 1 ppb would not be applied uniformly across all states, avoiding the consistency and equity problems. If 1 ppb captures the same relative amount of upwind contribution, then the fact that some upwind states impacts would not be considered significant and require a Step 3 analysis is reasonable. In fact, the Proposed Rule stated that "EPA's updated modeling, the amount of upwind contribution lost is 5%)". The same argument for fairness could be applied to a 1% standard which unduly burdens states to more stringent control requirements when applying these controls will result in little to no benefit of downwind Ozone. (This is further discussed in item 4.)

The August 2018 memorandum stated, “Each time EPA sets a new or revised NAAQS, states and EPA can evaluate collective contribution to identify an appropriate threshold for that NAAQS…conclusions made with respect to one NAAQS are not by default applicable to another NAAQS.” Yet here, EPA’s Proposed Rule makes the argument that “Consistency with past interstate transport actions…is also important.”

It is understood that generalizations and simplified assumptions are sometimes appropriate and necessary in a complex modeling analysis such as a national photochemical ozone evaluation. However, when the results are used to justify costly controls and monitoring on a significant number of industrial stationary sources in the state, further culpability refinements need to be assessed. Arbitrarily requiring controls across multiple non-EGU point sources in a state contributing less than 1ppb to a modeled ozone value greater than 70 ppb demands an extra step confirming that non-EGU sources are in fact the main contributors from each state.

2. *The use of 1% of the NAAQS as a meaningful level to evaluate other source/source geographies (especially on a state-basis) is flawed as it ignores the impact of the downwind nonattainment areas and other impacts from within the immediate vicinity around the area.*

Using a very small contribution simply means that more sources will be included as impacting downwind nonattainment. The selection of the level should be based on similar criteria that are used as part of an individual project evaluation, but with a much larger impact when combining emissions sources from an entire state. This is a substantial flaw in EPA’s approach and should be recognized along with the inherent bias and error of the model to determine applicable thresholds which is further discussed in item 6.

EPA ozone modeling evaluated baseline 8-hour impacts for 2023 and 2026 with contributions by state to any ozone NAAQS modeled exceedance. This information is contained in Appendix C: Ozone Contributions to Nonattainment & Maintenance-Only Receptors (Outside of California) in 2023 and 2026. The following table lists the state receptors in Appendix C where U. S. Steel facilities are located which contribute more than 0.71 ppb to a downwind ozone non-attainment (>70 ppb) receptor. The State of Illinois’s contribution to downwind ozone (including all sources, not merely EGUs and Non-EGUs) is the greatest with around 25% of the impact with Pennsylvania and Indiana coming next with around 10% impact on their downwind receptors. The remaining states only contribute around 2-3% of the downwind ozone impacts even when all sources are combined in the state (including natural sources and mobile sources and other sources not subject to the Proposed Rule).

State	USS Source	Receptor 2023 Max (ppb)	State Contribution (ppb)	Receptor 2026 Max (ppb)	State Contribution (ppb)
AL	Fairfield Works	Denton, TX: 72.2 Harris, TX: 72.0	Denton, TX: 0.71 Harris, TX: 0.88	NONE	NONE
AR	Big River Steel	Brazoria, TX: 72.3 Denton, TX: 72.2 Harris (55), TX: 72.0 Harris (34), TX: 71.6 Harris (35), TX: 71.6	Brazoria, TX: 1.39 Denton, TX: 0.76 Harris (55), TX: 1.0 Harris (34), TX: 1.38 Harris (35), TX: 1.34	Brazoria, TX: 71.2	Brazoria, TX: 1.30
CA	UPI	Yuma, AZ: 72.2 Douglas, CO: 72.3 Jefferson (6), CO: 73.3 Jefferson (11), CO: 74.4 Clark, NV: 71.0 Davis, UT: 75.1 Salt Lake (6), UT: 75.3 Salt Lake (11), UT: 74.9 Weber (2), UT: 72.5 Weber (3), UT: 71.5	Yuma, AZ: 5.09 Douglas, CO: 0.91 Jefferson (6), CO: 1.03 Jefferson (11), CO: 1.17 Clark, NV: 7.4 Davis, UT: 2.25 Salt Lake (6), UT: 2.46 Salt Lake (11), UT: 1.42 Weber (2), UT: 2.24 Weber (3), UT: 2.16	Yuma, AZ: 71.8 Douglas, CO: 71.1 Jefferson (6), CO: 72.3 Jefferson (11), CO: 73.3 Davis, UT: 73.9 Salt Lake (6), UT: 74.1 Salt Lake (13), UT: 74.0 Weber (2), UT: 71.7	Yuma, AZ: 4.85 Douglas, CO: 0.88 Jefferson (6), CO: 0.99 Jefferson (11), CO: 1.12 Davis, UT: 2.18 Salt Lake (6), UT: 2.38 Salt Lake (13), UT: 1.36 Weber (2), UT: 2.13
IL	Granite City Works	Kenosha (19), WI: 73.7 Kenosha (25), WI: 72.3 Racine, WI: 73.2	Kenosha (19), WI: 18.13 Kenosha (25), WI: 18.55 Racine, WI: 13.86	Kenosha (19), WI: 72.6 Kenosha (25), WI: 71.1 Racine, WI: 72.1	Kenosha (19), WI: 17.81 Kenosha (25), WI: 18.14 Racine, WI: 13.54
IN	Gary Works	Fairfield (7), CT: 75.1 Fairfield (3), CT: 76.4 New Haven, CT: 73.9 Cook (1), IL: 73.4 Cook (32), IL: 72.4 Cook (76), IL: 72.1 Cook (4201), IL: 73.4 Cook (2), IL: 73.0 Bucks, PA: 72.2 Kenosha (19), WI: 73.7 Kenosha (25), WI: 72.3 Racine, WI: 73.2	Fairfield (7), CT: 0.75 Fairfield (3), CT: 0.76 New Haven, CT: 0.87 Cook (1), IL: 5.44 Cook (32), IL: 7.03 Cook (76), IL: 6.21 Cook (4201), IL: 4.65 Cook (76), IL: 6.33 Bucks, PA: 0.73 Kenosha (19), WI: 6.6 Kenosha (25), WI: 7.1 Racine, WI: 6.6	Fairfield (7), CT: 73.7 Fairfield (3), CT: 74.8 New Haven, CT: 72.4 Cook (1), IL: 72.5 Cook (32), IL: 71.7 Cook (76), IL: 71.3 Cook (4201), IL: 72.4 Cook (2), IL: 72.0 Kenosha (19), WI: 72.6 Kenosha (25), WI: 71.1 Racine, WI: 72.1	Fairfield (7), CT: 0.71 Fairfield (3), CT: 0.71 New Haven, CT: 0.82 Cook (1), IL: 5.41 Cook (32), IL: 6.99 Cook (76), IL: 6.08 Cook (4201), IL: 4.54 Cook (2), IL: 6.18 Kenosha (19), WI: 6.43 Kenosha (25), WI: 6.98 Racine, WI: 6.52
MI	Great Lakes Works	Fairfield (17), CT: 73.7 Fairfield (7), CT: 75.1 Fairfield (3), CT: 76.4 New Haven, CT: 73.9 Cook (1), IL: 73.4 Cook (32), IL: 72.4 Cook (76), IL: 72.1 Cook (4201), IL: 73.4 Cook (2), IL: 73.0 Bucks, PA: 72.2 Kenosha (19), WI: 73.7 Kenosha (25), WI: 72.3 Racine, WI: 73.2	Fairfield (17), CT: 1.07 Fairfield (7), CT: 0.94 Fairfield (3), CT: 0.92 New Haven, CT: 1.27 Cook (1), IL: 0.93 Cook (32), IL: 1.21 Cook (76), IL: 1.54 Cook (4201), IL: 1.67 Cook (76), IL: 1.26 Bucks, PA: 0.75 Kenosha (19), WI: 1.07 Kenosha (25), WI: 1.17 Racine, WI: 1.02	Fairfield (17), CT: 72.2 Fairfield (7), CT: 73.7 Fairfield (3), CT: 74.8 New Haven, CT: 72.4 Cook (1), IL: 72.5 Cook (32), IL: 71.7 Cook (76), IL: 71.3 Cook (4201), IL: 72.4 Cook (2), IL: 72.0 Kenosha (19), WI: 72.6 Kenosha (25), WI: 71.1 Racine, WI: 72.1	Fairfield (17), CT: 1.02 Fairfield (7), CT: 0.89 Fairfield (3), CT: 0.88 New Haven, CT: 1.21 Cook (1), IL: 0.88 Cook (32), IL: 1.15 Cook (76), IL: 1.46 Cook (4201), IL: 1.58 Cook (2), IL: 1.19 Kenosha (19), WI: 1.03 Kenosha (25), WI: 1.11 Racine, WI: 0.96
MN	Keetac, Minntac	Cook (1), IL: 73.4 Cook (76), IL: 72.1	Cook (1), IL: 0.97 Cook (76), IL: 0.79	Cook (1), IL: 72.5 Cook (76), IL: 71.3	Cook (1), IL: 0.91 Cook (76), IL: 0.75
OH	PRO-TEC	Fairfield (17), CT: 73.7 Fairfield (7), CT: 75.1 Fairfield (3), CT: 76.4 New Haven, CT: 73.9 Cook (1), IL: 73.4 Cook (32), IL: 72.4 Cook (76), IL: 72.1 Cook (4201), IL: 73.4	Fairfield (17), CT: 1.18 Fairfield (7), CT: 1.87 Fairfield (3), CT: 1.90 New Haven, CT: 1.94 Cook (1), IL: 0.82 Cook (32), IL: 1.26 Cook (76), IL: 1.23 Cook (4201), IL: 1.23	Fairfield (17), CT: 72.2 Fairfield (7), CT: 73.7 Fairfield (3), CT: 74.8 New Haven, CT: 72.4 Cook (1), IL: 72.5 Cook (32), IL: 71.7 Cook (76), IL: 71.3 Cook (4201), IL: 72.4	Fairfield (17), CT: 1.10 Fairfield (7), CT: 1.76 Fairfield (3), CT: 1.78 New Haven, CT: 1.83 Cook (1), IL: 0.78 Cook (32), IL: 1.22 Cook (76), IL: 1.18 Cook (4201), IL: 1.19

		Cook (2), IL: 73.0 Bucks, PA: 72.2 Kenosha (19), WI: 73.7 Kenosha (25), WI: 72.3 Racine, WI: 73.2	Cook (2), IL: 1.69 Bucks, PA: 1.88 Kenosha (19), WI: 1.67 Kenosha (25), WI: 1.33 Racine, WI: 1.00	Cook (2), IL: 72.0 Kenosha (19), WI: 72.6 Kenosha (25), WI: 71.1 Racine, WI: 72.1	Cook (2), IL: 1.62 Kenosha (19), WI: 1.59 Kenosha (25), WI: 1.3 Racine, WI: 0.97
PA	Mon Valley Works	Fairfield (17), CT: 73.7 Fairfield (7), CT: 75.1 Fairfield (3), CT: 76.4 New Haven, CT: 73.9	Fairfield (17), CT: 5.44 Fairfield (7), CT: 6.37 Fairfield (3), CT: 6.90 New Haven, CT: 4.74	Fairfield (17), CT: 72.2 Fairfield (7), CT: 73.7 Fairfield (3), CT: 74.8 New Haven, CT: 72.4	Fairfield (17), CT: 5.32 Fairfield (7), CT: 6.36 Fairfield (3), CT: 6.82 New Haven, CT: 4.74
TX	Lone Star Tubular	Cook (32), IL: 72.4 Cook (4201), IL: 73.4 Cook (2), IL: 73.0 Kenosha (19), WI: 73.7 Kenosha (25), WI: 72.3 Racine, WI: 73.2	Cook (32), IL: 1.46 Cook (4201), IL: 1.15 Cook (2), IL: 1.58 Kenosha (19), WI: 1.72 Kenosha (25), WI: 1.81 Racine, WI: 1.34	Cook (32), IL: 71.7 Cook (4201), IL: 72.4 Cook (2), IL: 72.0 Kenosha (19), WI: 72.6 Kenosha (25), WI: 71.1 Racine, WI: 72.1	Cook (32), IL: 1.39 Cook (4201), IL: 1.09 Cook (2), IL: 1.49 Kenosha (19), WI: 1.61 Kenosha (25), WI: 1.70 Racine, WI: 1.25

3. *EPA's ozone modeling results indicate that the non-EGU sources' contributions are a small fraction of the state's total downwind impacts to ozone non-attainment receptors. Without the complete culpability of a state's total impacts to downwind receptors identifying the main contributors from each state, EPA's argument that non-EGUs need to be controlled for future ozone NAAQS demonstration is not justifiable for the proposed rule.*

Section 4.1 of the "**Air Quality Modeling Technical Support Document: FIP Addressing Regional Ozone Transport for 2015 Ozone NAAQS Proposed Rule Making**" explains the make-up of the state-wide emissions. They include point sources (electric generating units (EGUs) and non-EGU's (combustion stacks)), non-point sources (mobile vehicle exhaust, other man-made (anthropogenic) sources), and biogenic sources (forest fires). The 2026 Ozone NAAQS modeling was the only run that sub-divided state-specific culpability into EGU and non-EGU source culpabilities. The USS facilities would be classified as a non-EGU source and are assumed included within the non-EGU source group contributions. EPA 2026 ozone modeling results provided state-sector contributions for all ozone NAAQS non-attainment receptors further sub-divided into EGU and non-EGU sources; it did not include a source category for non-point anthropogenic sources (on-road and off-road vehicles) or biogenic sources. The docket file "**EPA-HQ-OAR-2021-0668-0070_content_2026_non-egu-state-sector_contribution.xlsx**" provided this apportionment for all the 2026 receptors in Appendix C.

The tables below summarize each state U. S. Steel facilities reside in non-EGU contribution to the modeled total ozone in ppb. In general, non-EGU sources are around 20% of the state-wide contributions and when combined with the EGU's are approximately 50% of each state's contributions. For 46 receptors (80%) of the 57 receptor, non-EGU contributions are insignificant enough that subtracting the entire non-EGU inventory from each receptor would not affect whether the state was a "significant" contributor to the ozone NAAQS assuming EPA's significance threshold for States of 0.71

ppb. The remaining state impacts by process of elimination are some fraction of mobile sources, non-point sources, and biogenic sources.

2026 MN-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Illinois (001) Results	72.5	0.91	0.19	0.04
Illinois (076) Results	71.3	0.75	0.18	0.03

2026 AR-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Texas (1004) Results	71.2	1.3	0.28	0.19

2026 CA-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Arizona (8011) Results	71.8	4.85	0.41	0.22
Colorado (004) Results	71.1	0.88	0.1	0.04
Colorado (006) Results	72.3	0.99	0.11	0.05
Colorado (011) Results	73.3	1.12	0.12	0.05
Utah (004) Results	73.9	2.18	0.29	0.12
Utah (006) Results	74.1	2.38	0.31	0.13
Utah (013) Results	74.0	1.36	0.16	0.07
Utah (002) Results	71.7	2.13	0.29	0.11

2026 IL-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Wisconsin (019) Results	72.6	17.81	1.99	0.65
Wisconsin (025) Results	71.1	18.14	2.07	0.81
Wisconsin (020) Results	72.1	13.54	1.52	0.48

2026 IN-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Wisconsin (019) Results	72.6	6.43	3.03	0.37
Wisconsin (025) Results	71.1	6.98	3.38	0.36
Wisconsin (020) Results	72.1	6.52	3.22	0.37
Illinois (001) Results	72.5	5.41	2.72	0.31
Illinois (032) Results	71.7	6.99	3.57	0.45
Illinois (076) Results	71.3	6.08	2.87	0.37
Illinois (4201) Results	72.4	4.54	1.94	0.32
Illinois (002) Results	72	6.18	2.67	0.42
Connecticut (007) Results	73.7	0.71	0.13	0.11
Connecticut (003) Results	74.8	0.71	0.14	0.11
Connecticut (002) Results	72.4	0.82	0.16	0.12

2026 MI-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)

Wisconsin (019) Results	72.6	1.03	0.16	0.13
Wisconsin (025) Results	71.1	1.11	0.16	0.16
Wisconsin (020) Results	72.1	0.96	0.14	0.13
Illinois (001) Results	72.5	0.88	0.15	0.14
Illinois (032) Results	71.7	1.15	0.18	0.18
Illinois (076) Results	71.3	1.46	0.23	0.24
Illinois (4201) Results	72.4	1.58	0.24	0.26
Illinois (002) Results	72	1.19	0.18	0.18
Connecticut (017) Results	72.2	1.82	0.18	0.14
Connecticut (007) Results	73.7	0.89	0.17	0.15
Connecticut (003) Results	74.8	0.88	0.17	0.14
Connecticut (002) Results	72.4	1.21	0.2	0.19

2026 OH-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Wisconsin (019) Results	72.6	1.59	0.39	0.11
Wisconsin (025) Results	71.1	1.3	0.38	0.06
Wisconsin (020) Results	72.1	0.97	0.25	0.1
Illinois (001) Results	72.5	0.78	0.17	0.05
Illinois (032) Results	71.7	1.22	0.32	0.09
Illinois (076) Results	71.3	1.18	0.31	0.09
Illinois (4201) Results	72.4	1.19	0.31	0.08
Illinois (002) Results	72	1.62	0.41	0.13
Connecticut (017) Results	72.2	1.1	0.24	0.13
Connecticut (007) Results	73.7	1.76	0.36	0.27
Connecticut (003) Results	74.8	1.78	0.36	0.28
Connecticut (002) Results	72.4	1.83	0.41	0.25

2026 PA-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Connecticut (017) Results	72.2	5.32	0.81	0.85
Connecticut (007) Results	73.7	6.36	1.03	0.97
Connecticut (003) Results	74.8	6.82	1.09	1.03
Connecticut (002) Results	72.4	4.74	0.81	0.72

2026 TX-Specific Scenario (ppb)	Total Ozone (ppb)	State Impacts (ppb)	Non-EGU (ppb)	EGU (ppb)
Wisconsin (019) Results	72.6	1.61	0.22	0.09
Wisconsin (025) Results	71.1	1.7	0.25	0.09
Wisconsin (020) Results	72.1	1.25	0.19	0.07
Illinois (032) Results	71.7	1.39	0.18	0.07
Illinois (4201) Results	72.4	1.09	0.13	0.05
Illinois (002) Results	72	1.49	0.2	0.08

a. With particular focus on Minnesota's modeled impacts and industrial sources, U.S. Steel has two northeast Minnesota facilities included in the analysis: Keetac and Minntac. Minnesota's non-EGU source group contributions (all non-EGU's including Minntac and Keetac) to the state's culpability in Cook County, IL were 0.19 and 0.18 ppb. The distance and time needed for these sources' NO_X emissions to travel to Chicago to chemically react and create ozone at this monitor seems unlikely and was further investigated. EPA provided the dates and times of the 2016 top-10 ozone days for the two IL monitors Minnesota contributed more than 0.71 ppb and using the HYSPLIT web-based platform, preliminary 48-hr back trajectories were processed for these dates. While a simplified approach, it provided results that require EPA to re-assess their modeling culpability. In general, the preceding hours to the highest ozone impact days had very little to zero winds coming from the northwest (i.e. Minnesota).

4. *EPA's analysis chose to not address any reductions on non-point sources like mobile traffic which include light and heavy-duty trucks and passenger vehicles. However, EPA's modeling indicates the mobile sources are a higher fraction of an upwind state's contribution then non-EGU sources. EPA's rule should include federally enforceable limits on mobile traffic as a larger source contributor rather than requiring additional NO_X controls and limits on non-EGU point sources that contribute far less.*

"The EPA accounted for mobile source emissions reductions resulting from other federally enforceable regulatory programs in the development of emissions inventories used to support analysis for this proposed rulemaking, and the EPA does not evaluate any mobile source control measures in its Step 3 evaluation in this proposal." Item 3 highlights the need for a more refined breakdown of state-source contributions to modeled ozone non-attainment. There is no mention in the air quality modeling technical support document of the word "mobile" or "vehicle." (Federal Register Vol 87. No. 66 VI.A.)

On May 16, 2022, the National Association of Clean Air Agencies (NACAA) provided comments on EPA's Notice of Proposed Rulemaking "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards" which included relevant information to this proposed Good Neighbor Ozone Rulemaking. NACAA's main point is how the last 20 years has seen a significant reduction of NO_X from point sources while heavy-duty vehicles have not made much progress. This plays out in nationwide Ozone attainment where the largest contributors across many regions of the US are mobile sources, particularly heavy-duty trucks. Some pertinent quotes from NACAA's comment letter are provided as further reasons to use the evidence from the ozone modeling to identify the highest contributing sources (regardless of type) and focus on those that provide the greatest ozone downwind reductions.

> "HD (heavy duty) trucks will continue to be one of the largest contributors to the national mobile source NOX inventory in 2028 without additional regulations to reduce emissions."
>
> "The excessive emissions from HD trucks are a primary cause, contributing substantial emissions of NOX – the key pollutant contributing to the formation of ozone and PM2.5."
>
> "While state and local agencies have made great strides in reducing emissions from stationary sources, for the most part they lack the authority to regulate mobile sources and never do they have the authority to regulate mobile sources upwind of or across their borders. The regulation of mobile sources is an authority that lies almost entirely within the purview of the federal government."
>
> "**Many areas will be forced to adopt severe limits on stationary sources**, for which they have authority to control**, at ever-increasing costs, if reductions from such sources are even available**." (Emphasis added)
>
> "The onroad mobile sector is the largest contributor of NOX emissions in Wisconsin. Recent modeling done by the Lake Michigan Air Directors Consortium indicates onroad diesel vehicles, the vast majority of which are heavy-duty vehicles, contribute up to 8 ppb of 11% of ozone at Wisconsin's lakeshore nonattainment monitors."
>
> "Recent source apportionment modeling for 2023 (Denver Metro, CO) demonstrates that NOX emissions are driving ozone formation at monitors throughout the region and that medium- and heavy-duty truck traffic is a significant contributor to ozone formation."

The last two quotes are relevant for the Kenosha and Racine, WI monitors and Denver, CO monitor that are part of the list where non-EGU sources in upwind states are being considered for further NO_X reductions to reduce ozone impacts. The regional scale modeling conducted by these collectives at a finer scale highlight how significant heavy-duty vehicle traffic is to the ozone impacts. The 2023 apportionment modeling listed in the above quote lists the total mobile vehicle contribution to the Denver 011 monitor for a 10-day period 8-hour ozone concentration of 20 ppb as 31% with 26% of the 31% due to light-duty vehicles. The non-EGU sources compose 15% of the total (i.e., all non-EGU industries combined are still less than half the contribution that mobile sources add to the state's linked receptors).

5. *The non-EGU controls considered for Tier 1 and Tier 2 sources do not meaningfully reduce the ozone concentrations at non-attainment receptors. EPA's state contribution significance threshold of 0.71 ppb exceeds the*

potential downwind ozone reductions through excessive controls on these state's non-EGU sources.

As part of its evaluation, EPA defined "impactful boilers" using 3 criteria[1]: (1) estimated maximum air quality contribution at an individual receptor of greater than or equal to 0.0025 ppb or estimated total contribution across downwind receptors of greater than or equal to 0.01 ppb (2) controls that cost up to $7,500 per ton (3) estimated maximum air quality improvement at an individual receptor of greater than 0.001 ppb.

EPA acknowledges the fact that the model is not precise enough to confirm these types of regulatory decisions but does so, nonetheless. When trying to define the impact of individual sources on downwind ozone nonattainment areas, EPA is trying to draw the conclusion that a source with a 0.0025 ppb contribution is "impactful". This level is not impactful and as a statistical matter cannot even be differentiated by the model used by EPA.

Additional information included in "**Appendix A**" specifies industries maximum contributions to downwind ozone receptors. Table A-2 lists both Iron and Steel Mills and Ferroalloy and Nonmetallic Mineral Mining and Quarrying separately. Iron and Steel Mill's maximum downwind impact is 0.129 ppb and contributes more than 0.01 ppb to 11 downwind receptors. Nonmetallic mineral mining's maximum downwind impact is 0.035 ppb and has only 4 receptors that it contributes more than 0.01 ppb.

As noted in the above section 3, in almost all states evaluated by EPA, non-EGU contributions are so insignificant that even if every single non-EGU source was wholly eliminated, that would not affect the significance of a state's contribution to its linked receptors. By contrast the overall contribution of other sources (including mobile sources within the nonattainment area) are orders of magnitude greater than this level of impact and not being considered for reductions. Accordingly, it appears the Proposed Rule was designed to make sources across the country address ozone air quality issues within major metropolitan areas where the largest impacts come from mobile and area source emissions. The underlying modeling does not justify a finding that non-EGU sources, whether combined or separately, are significant contributors to non-attainment.

6. *EPA's reliance on a significance of 0.71 ppb is faulty when taking into consideration their model performance evaluation of their ozone modeling evaluation. A higher ppb downwind impacts threshold than 0.71 ppb should*

be considered when the modeling TSD states "the regional mean bias of the model is +/- 5 ppb and the mean error is between 6 and 7 ppb on average for all days during the period May through September in each region."

The model performance at each non-attainment receptor was provided in the proposed rule docket file "EPA-HQ-OAR-2021-0668-0071_content(2016CAMxperformance).xlsx". The following table lists the model's performance reflected by the (1) difference between the model vs observed mean 2016 concentration, (2) calculated mean bias, (3) mean error, and (4) standard deviation. In general, the receptors downwind of U.S. Steel located states had a higher variability in model performance than the +/- 5 ppb overall regional model bias. All receptors modeled ozone concentrations less than the observed concentrations underpredicted ozone concentrations with a mean error ranging from 7-17 ppb. Given the substantial model error compared to the extremely low alleged upwind state contributions, EPA's model is not capable of reliably differentiating between any effect within an order of magnitude of the significance threshold selected by EPA.

Receptor Information	Model/Obs. (ppb)	Mean Bias (ppb)	Mean Error (ppb)	Standard Deviation (ppb)
Yuma, AZ (8011)	53.39/65.76	-12.37	12.84	7.43
Douglas, CO (004)	61.0/67.64	-6.64	7.79	7.58
Jefferson, CO (006)	60.30/67.42	-7.12	8.00	7.49
Jefferson, CO (011)	60.76/68.69	-7.92	8.61	8.19
Fairfield, CT (017)	67.10/70.07	-2.97	8.65	15.75
Fairfield, CT (007)	66.12/70.67	-4.56	8.61	10.88
Fairfield, CT (003)	67.36/72.71	-5.36	8.58	12.27
New Haven, CT (002)	64.60/69.97	-5.36	7.04	10.81
Cook County, IL (001)	60.75/68.97	-8.22	11.13	8.16
Cook County, IL (032)	54.74/69.08	-14.34	14.60	8.98
Cook County, IL (076)	57.87/67.77	-9.90	11.85	8.65
Cook County, IL (4201)	57.02/68.56	-11.54	12.66	10.86
Cook County, IL (002)	58.01/67.85	-9.84	10.31	9.76
Brazoria, TX (004)	56.84/65.34	-8.50	8.57	8.13
Davis, UT (004)	56.47/66.35	-9.88	10.24	6.39
Salt Lake, UT (006)	58.30/67.90	-9.60	11.16	6.35
Salt Lake, UT (013)	55.60/66.85	-11.25	11.38	5.99
Weber, UT (002)	55.39/66.07	-10.68	10.79	6.11
Kenosha, WI (019)	53.21/70.35	-17.14	17.79	11.85
Kenosha, WI (025)	55.62/68.33	-12.71	12.94	9.37
Racine, WI (020)	53.06/69.34	-16.29	16.75	9.80

III. Installation and Permitting Schedule Challenges.

A. Is the proposed permit schedule for required new NO_X controls and/or construction reasonable based on current permitting issuance timelines?

1. The amount of time it takes for an air permit application review and issuance of an air permit varies by state and source type. An optimistic assumption is the application approval process in general will be swift and streamlined due to the large number of sources requiring additional control and monitoring equipment to reduce NO_X emissions. A more likely outcome, based on experience in certain states, is that the combination of staff availability and the large volume of permit applications to review and approve makes the current schedule unachievable.

Each state has different approaches to reviewing an air permit application and issuing the air permit for an existing stationary source. Some require more information and scrutiny of proposed updates than others which effects each state's ability to meet the 2026 deadline for the non-EGU to comply with the proposed rule. Minnesota in particular has some of the longest permitting review times in the country currently without the addition of this many permit applications in such a short timeframe. The table below lists out the likely timeline for each Minnesota USS facility to receive an approval of their air permit application and the assumptions of what the application will entail. This is without considering the construction and installation schedule.

Permitting Stage	Timeframe	Assumptions
Prepare application	5 months	Minor Amendment on existing Major Source; Keetac air permit requires Equivalent or Better (EBD) dispersion modeling analysis on "changes that affect any modeled parameter" in the SO2 and NO2 source list.
Application submittal	1.5 months	Currently 6 weeks wait time for a permit application assignation at MPCA
Regulatory approval	11.5 months	MPCA online permit flexibility table lists Individual part 70 permits issuance time as 6-12 months of starting work (9 months is mid-point); plus 30 day public notice, plus EPA 45-day review
Total	18 months	Assumes EBD demonstration acceptable and no negative comments from EPA or public

Based on the current situation, it will take a year and a half to complete the air permit application process and approve the air permit to begin project construction. The current queue timeline of 1.5 years is likely subject to change and increase with the large volume of projects that will be arriving simultaneously to meet the proposed construction schedule of this proposed

Good Neighbor Rule. In addition to the time needed just to obtain initial permits, new equipment installation scheduling will be affected by logistical/supply chain issues related to multiple sources needing upgrades at the same time

B. New Equipment Installation Scheduling will be affected by permit timeline challenges.

1. The proposed rule as written required all facilities to install controls by 2026. EPA should revise the schedule for installation as it is infeasible as currently written for a few reasons. Most of the facilities that are subject to installing controls will require retrofitting of existing equipment, therefore will require time to engineer and design the modifications required for installation of the controls, which could take months and years depending on the facility and equipment. Once modifications for existing equipment and proposed controls are designed, procurement of the necessary materials could take months and years due to potential supply chain issues. Most facilities will be competing to obtain materials from the same suppliers as the number of suppliers for the proposed controls is a very small group. Therefore, if EPA still determines it is feasible for the facilities to install the proposed controls after review and consideration of other supporting information as to why the proposed rule is infeasible, EPA should revise the proposed installation schedule by 5 years to allow sufficient time to design, procure, construct, and startup the proposed control equipment for a compliant demonstration.

IV. Infeasibility of SCR Installation for Iron and Steel Mills and Ferroalloy Manufacturing Emission Units

Table VII.C.3 – Summary of Proposed NOx Emissions Limits for Iron and Steel and Ferroalloy Manufacturing Emissions Units of the proposed rule lists 10 types of emissions units along with the proposed NOx emissions standard or requirement for each. A Regional Haze Four-Factor Analysis for NOx and SO2 Emission Controls was prepared for USS Gary Works in September of 2020. This analysis covered the No. 3 Sinter Plant Sinter Strands, the No. 14 Blast Furnace Stoves and Casthouse, and the 84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4 and Waste Heat Boilers No. 1 and No. 2. This analysis covers three emissions units included in Table VII.C.3 of the proposed rule – blast furnace, reheat furnace, and boiler (natural gas-fired). The results of the Gary Works' FFA found that:

- For the No. 14 Blast Furnace (Stoves and Casthouse)
    - Already utilize low-NOx fuel combustion (blast furnace gas) as a NOx emission control measure,
    - There is no reasonable set of NOx emission control measures beyond what is currently installed and operated for these emission units, and
    - The existing emission control measures are equivalent to those determined to be the Best Available Control Technology (BACT) in a recent BACT analysis and, therefore, are considered effective emission controls.

- For the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers
  - Low-NOx Burners (LNB) were an available NOx emission control measures beyond what is currently installed and operated for these emission units, but LNB installation on the 84" Hot Strip Mill Reheat Furnaces and Waste Heat Boilers are not cost-effective, based on the associated cost-effectiveness values ($ per ton of emissions reduction).
- Additional emission control measures could impact the economic viability of the company to continue to operate in competitive economic markets. Gary Works, as well as the entire integrated iron and steel mill industry, is highly sensitive to incremental capital and operating costs due to substantial fluctuation in global economic markets. Any additional emission control measures would be a substantial barrier for the facility to continue to operate and are therefore unreasonable and inappropriate.

EPA projects that use of LNB or LNB plus SCR will result in minimally 20-50% NOx reduction efficiency if implemented on blast furnaces, reheat furnaces, and boilers. The Gary Works' FFA is one example that found that implementing additional NOx controls on these emissions units is technically and/or economically infeasible. The proposed requirements are not supported by the necessary engineering analyses and contradict past Best Available Control Technology (BACT) determinations established by permitting authorities.

For Electric Arc Furnaces, EPA is proposing a NOx emissions standard of 0.15 lb/ton steel. A RACT/BACT/LAER Clearinghouse search returns 3 LAER determinations with emissions limits of 0.27 lb/T, 0.27 lb/T, and 0.35 lb/T for Nucor Kankakee (2021, RLBCID = IL-0132), Nucor Auburn (2006, RBLCID = NY-0099), and Republic Engineered Products (2006, RBLCID = OH-0302), respectively. EPA's proposed standard contradicts these LAER determinations established by permitting authorities. Also, for CMC Steel Oklahoma (2016, RBLCID = OK-0173) the Pollutant Compliance Notes state: 'The application proposes oxy-firing as BACT for NOx to a level of 0.3 lb/ton of steel melted. This level is somewhat higher than the lowest NOx level shown on RBLC for electric arc furnaces, but the proposed BACT level has been demonstrated by stack testing on a similar mill, whereas a demonstration is not readily available that the 0.2 lb/ton has actually been met in practice.' Based on the above, proposing a NOx limit for EAFs across the industry that is 45-55% lower than the limits from the LAER determinations has no technical basis, is stricter than any standard imposed by EPA under any program including LAER, and is not reasonable.

For Ladle/Tundish Preheaters, EPA is proposing a NOx emissions requirement of 0.06 lb/MMBTU. An RBLC search returns a LAER determination for Gerdau Macsteel Monroe (2018, RBLICID = MI-0438) with an emission limit of 0.08 lb/mmbtu (low NOx burners, use of NG fuel, and good combustion practices), which is above the 0.06 lb/mmbtu limit EPA is proposing. EPA's proposed NOx requirement for Ladle/Tundish Preheaters contradicts the 2021 Nucor Kankakee BACT determination and the 2018 Gerdau Macsteel Monroe LAER determination and has no technical basis.

For Reheat Furnaces, EPA is proposing a NOx emissions requirement of 0.05 lb/MMBTU. A search of the RBLC returns a RACT determination for Gerdau Sayreville Billet Reheat Furnace (2018, RBLCID = NJ-0087) with a NOx emission limit of 0.1 lb/mmbtu (low-NOx burners). Also, there are multiple types of reheat furnaces – billet, slab, walking beam, etc. It is not acceptable to group the reheat furnace types together and propose an emission limit that is 50% lower than the 2018 Gerdau Sayreville RACT determination. The Sterling Permit noted by EPA (Sterling Steel CO LLC (IL) 5/21/19 Construction Permit (Permit ID: 19020002) is for a new reheat furnace equipped with low-NOx natural gas-fired burners designed to emit no more than 0.073 lb of NOx/MMBTU to replace a reheat furnace that had reached end-of-life. It is not a retrofit of existing equipment. The permit states that the 'new reheat furnace will be more energy efficient than the existing furnace with less burner capacity than the existing unit.' It is not appropriate for EPA to propose a reheat furnace NOx emission limit based on a permit for new equipment/replacement in kind as most facilities would be looking at a retrofit of existing equipment.

For Vacuum Degassers, EPA is proposing a NOx emissions requirement of 0.03 lb/MMBTU, however, it is unclear why Vacuum Degasssers are included in this category at all. Vacuum Degassers themselves do not emit NOx, and any NOx emissions are only associated with the control device (flare) typically used as a control device for CO emissions from a Degasser. Also, in the RBLC the two facilities referenced by EPA, Nucor Darlington (RBLCID = SC-0197) and Nucor Tuscaloosa (RBLCID = AL-0275 and AL-0301) note that there is a flare used to control emissions; therefore, it is not reasonable for EPA to propose an industry-wide additional 40% NOx reduction by use of SCR without any demonstration that an SCR has or could be installed on a flare.

For Coke Ovens, EPA is proposing a NOx emissions requirement of 0.15 lb/ton (charging) and 0.015 lb/ton (pushing). A search of the RBLC indicates that the 0.019 lb/ton limit was a LAER determination (work practices) for Middletown Coke. EPA's proposed standard contradicts this LAER determination previously established by permitting authorities. Also, Middletown Coke is not part of the Iron and Steel and Ferroalloy Manufacturing industry as denoted by their 4-digit NAICS code (3241). Using an emission limit for units in a different industry that operate differently as the basis for Coke Ovens in the Iron and Steel and Ferroalloy Manufacturing industry is not appropriate.

Appendix A: Back Trajectories for 8-hr Ozone Top 10 Impact

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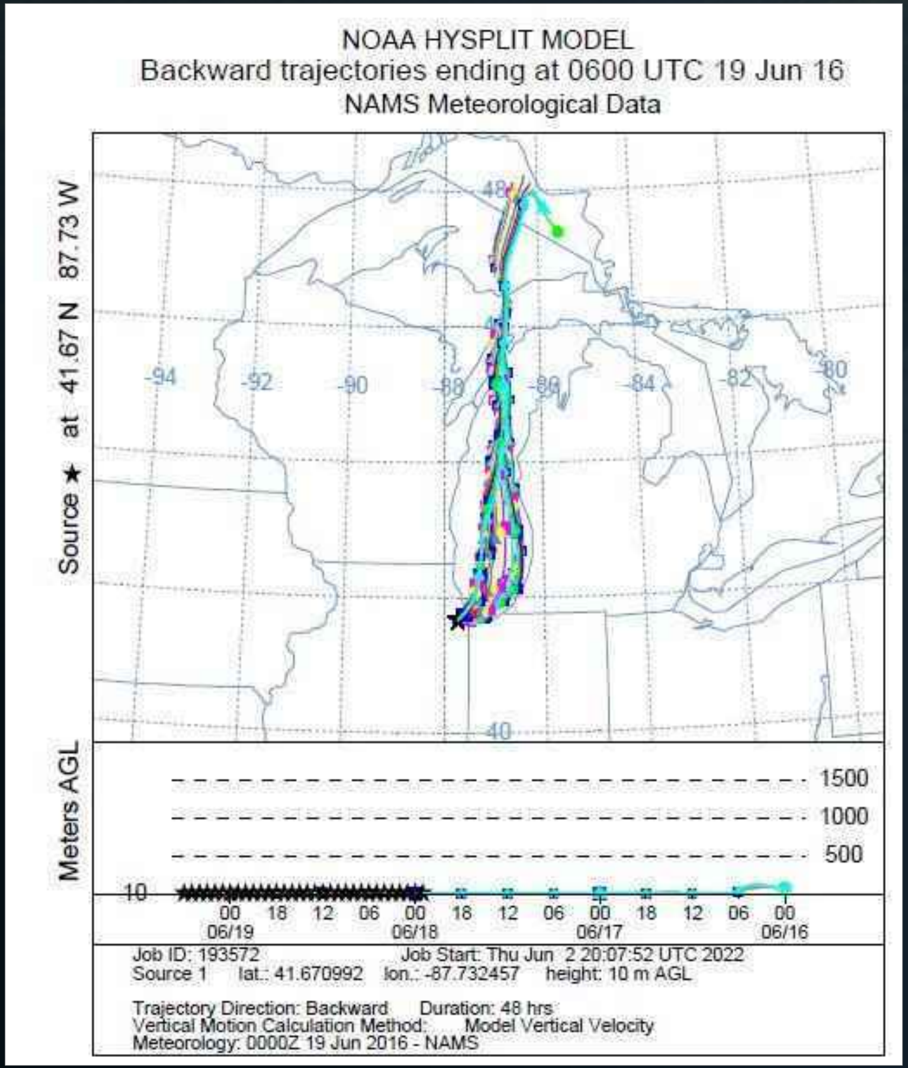
Back Trajectories for 8-hr Ozone Top 10 Impact Days

Cook County, IL Monitor 17-13-0001

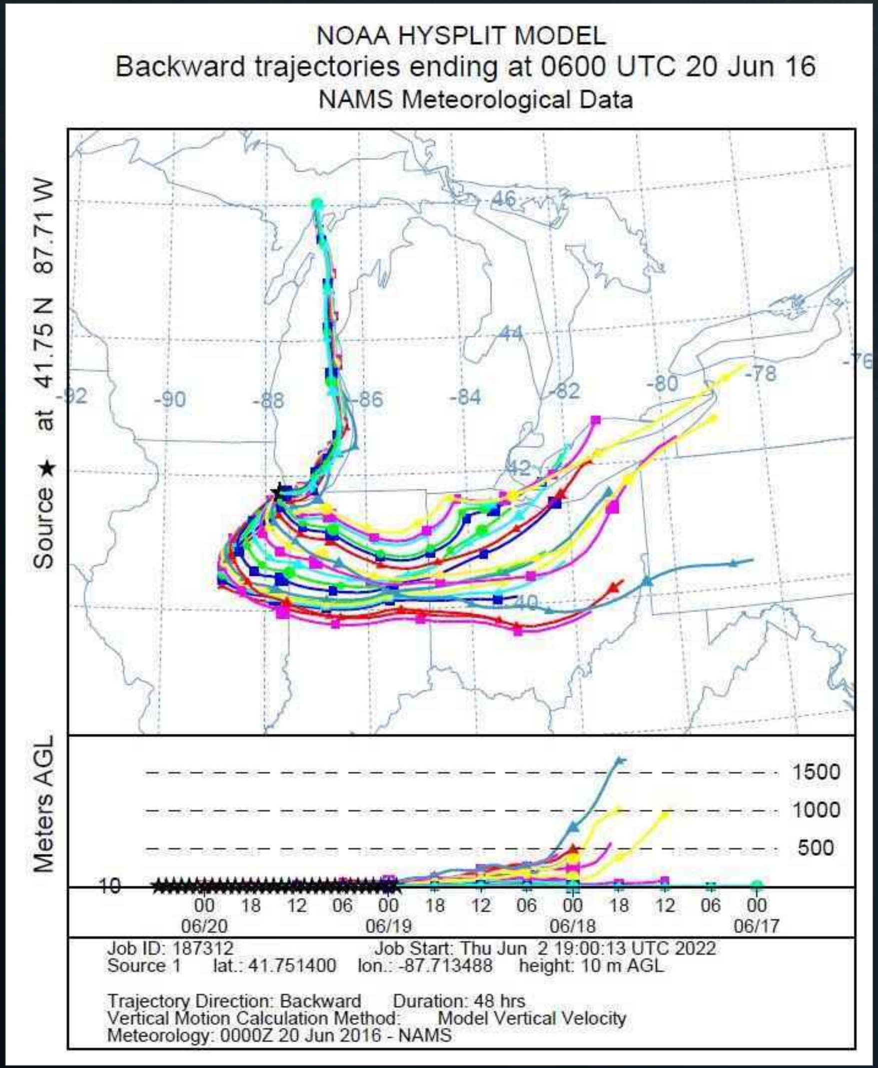
Cook County, IL Monitor 17-13-0076

Cook County, IL 17-13-0001: June 18, 2016



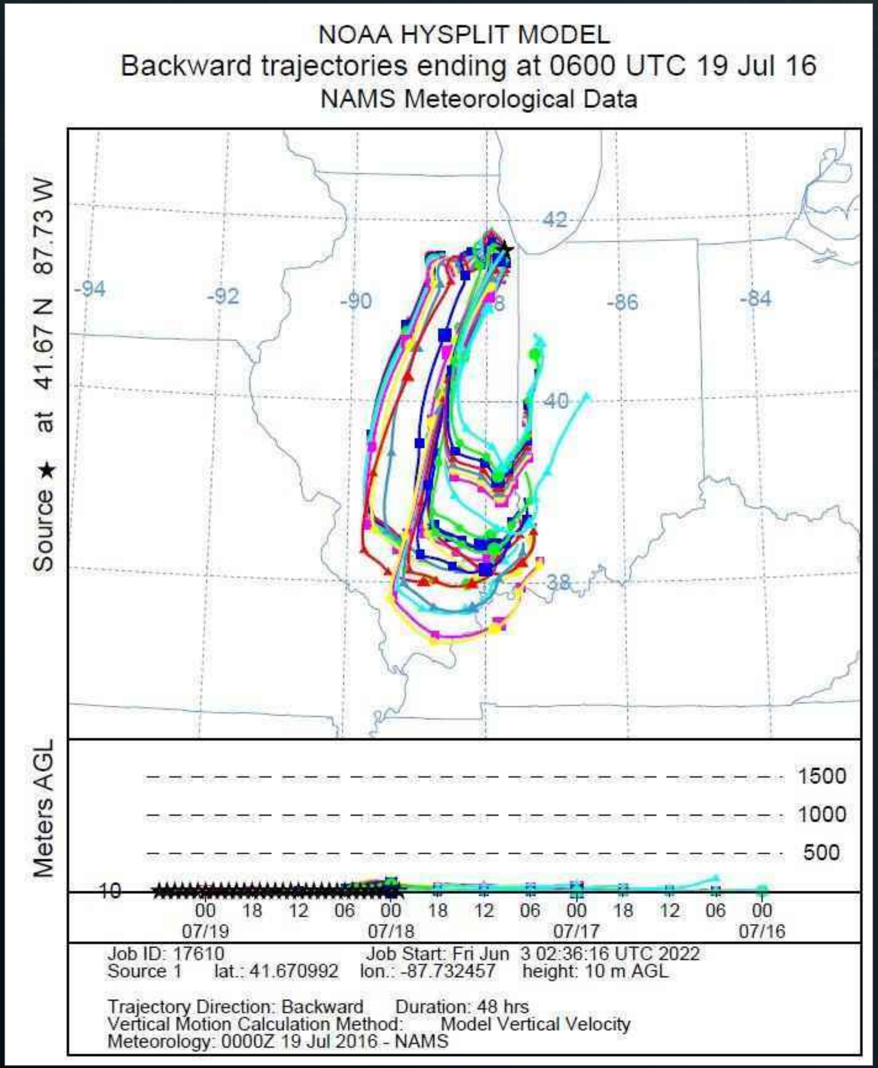
- Looking back 48-hrs from end of 6/18
- No likely MN contribution

Cook County, IL 17-13-0076: June 19, 2016



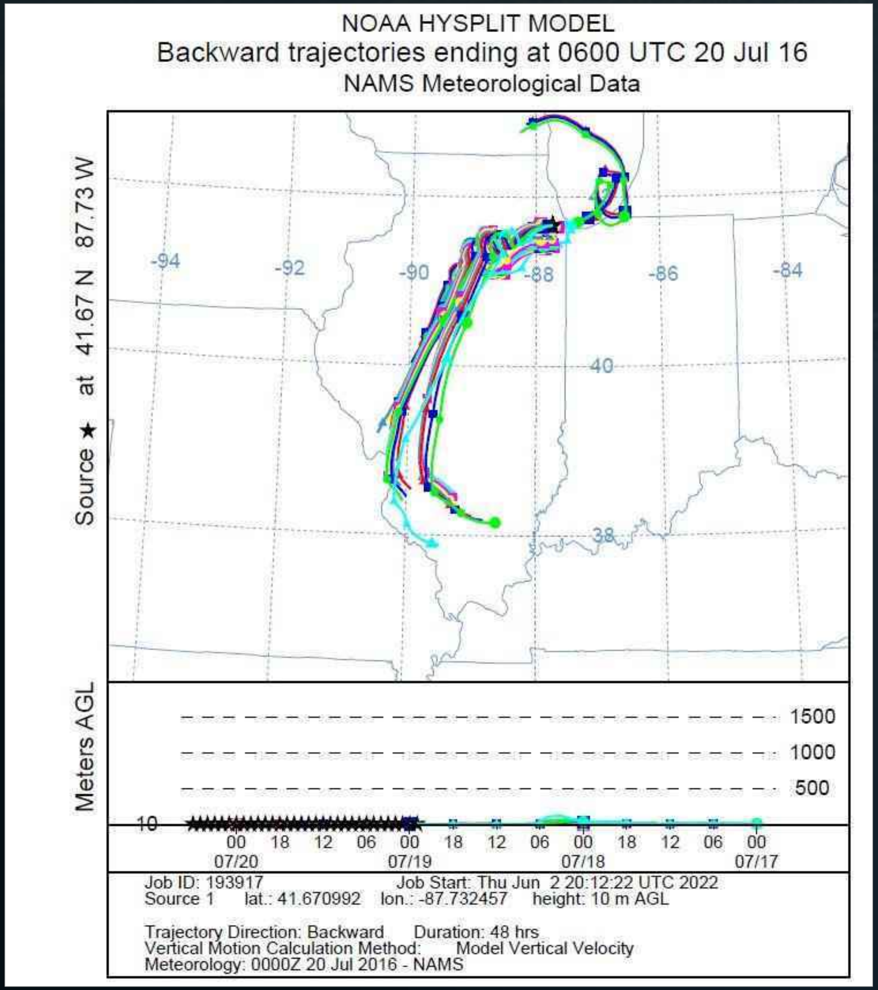
- Looking back 48-hrs from end of 6/19
- No likely MN contribution

Cook County, IL 17-13-0001/17-13-0076: July 18, 2016



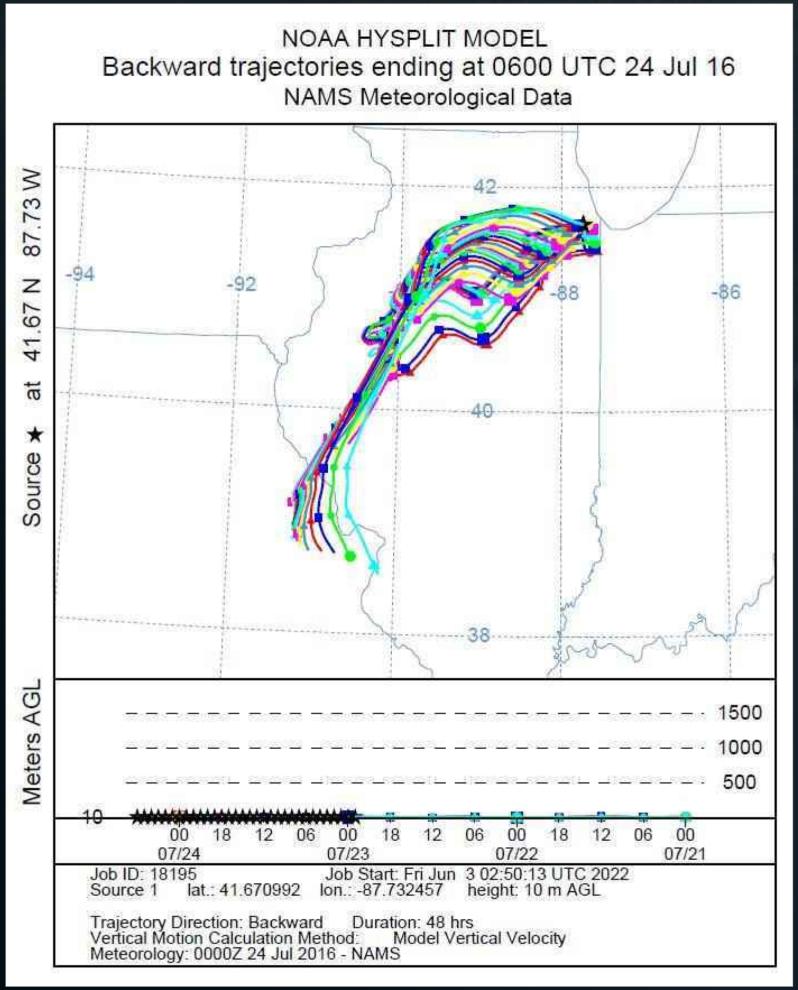
- Looking back 48-hrs from end of 7/18
- No likely MN contributions

Cook County, IL 17-13-0001/17-13-0076: July 19, 2016



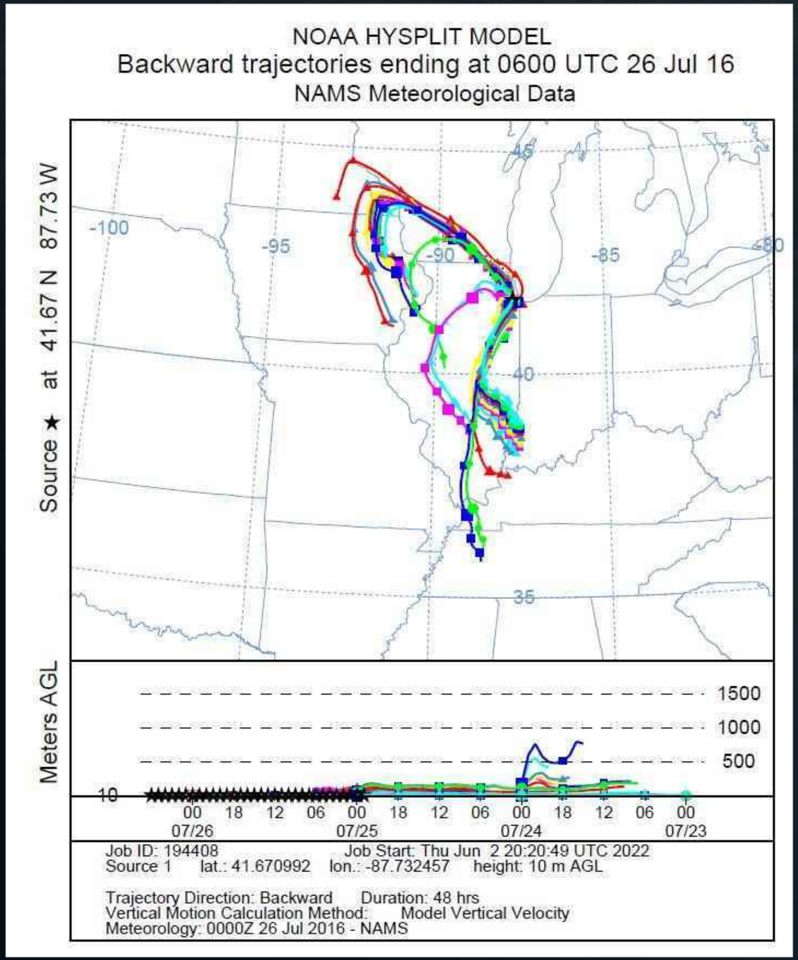
- Looking back 48-hrs from end of 7/19
- No likely MN contributions

Cook County, IL 17-13-0001/17-13-0076: July 23, 2016



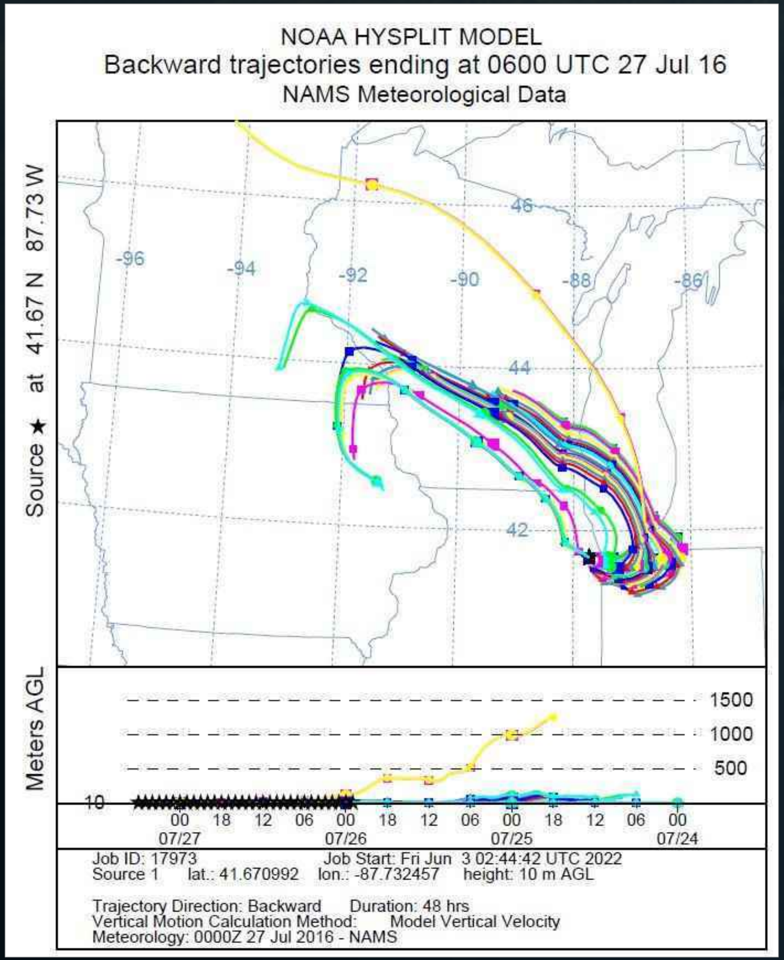
- Looking back 48-hrs from end of 7/23
- No likely MN contributions

Cook County, IL 17-13-0001/17-13-0076: July 25, 2016



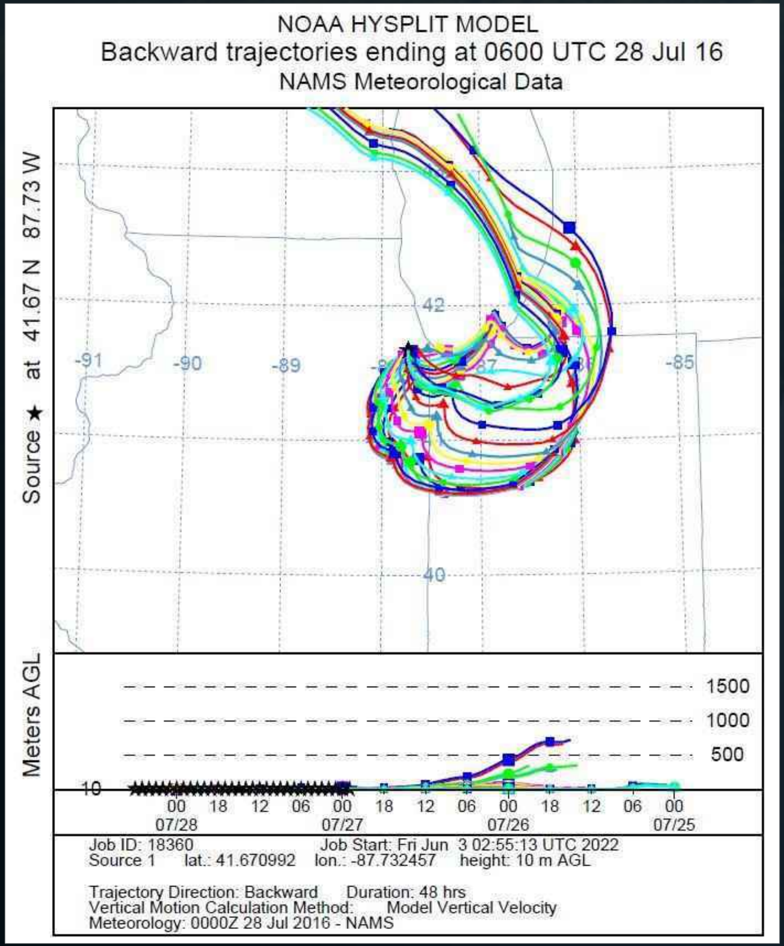
- Looking back 48-hrs from end of 7/25
- No likely MN contributions

Cook County, IL 17-13-0001/17-13-0076: July 26, 2016



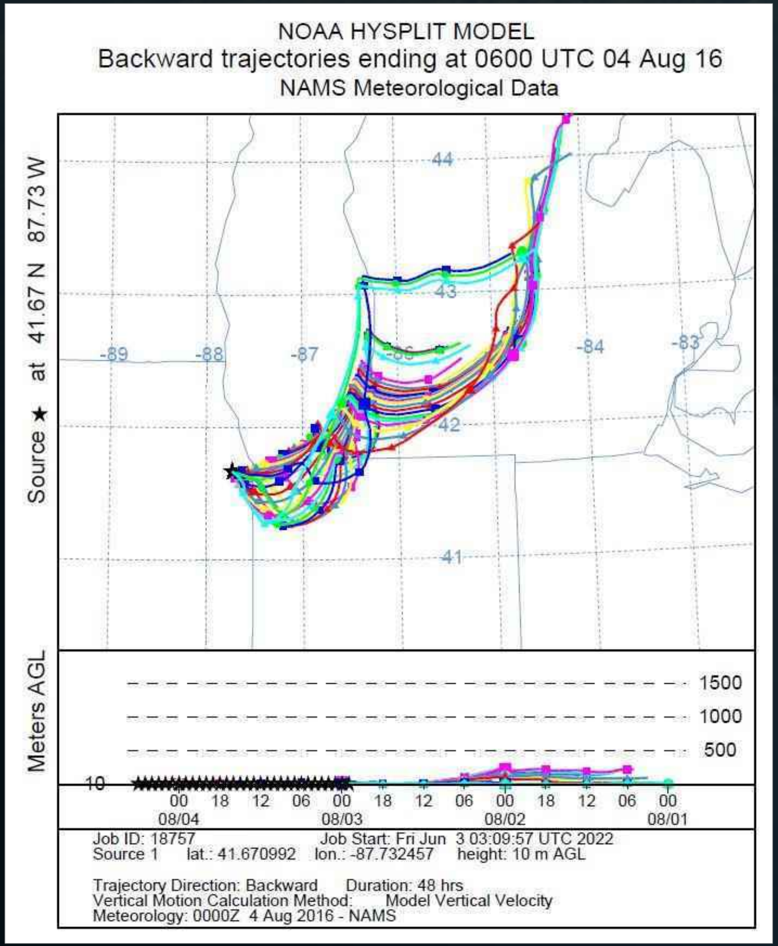
- Looking back 48-hrs from end of 7/26

Cook County, IL 17-13-0001/17-13-0076: July 27, 2016



- Looking back 48-hrs from end of 7/27
- No likely MN contribution

Cook County, IL 17-13-0001/17-13-0076: August 3, 2016



- Looking back 48-hrs from end of 8/3
- No likely MN contributions

Cook County, IL 17-13-0001/17-13-0076: August 4, 2016

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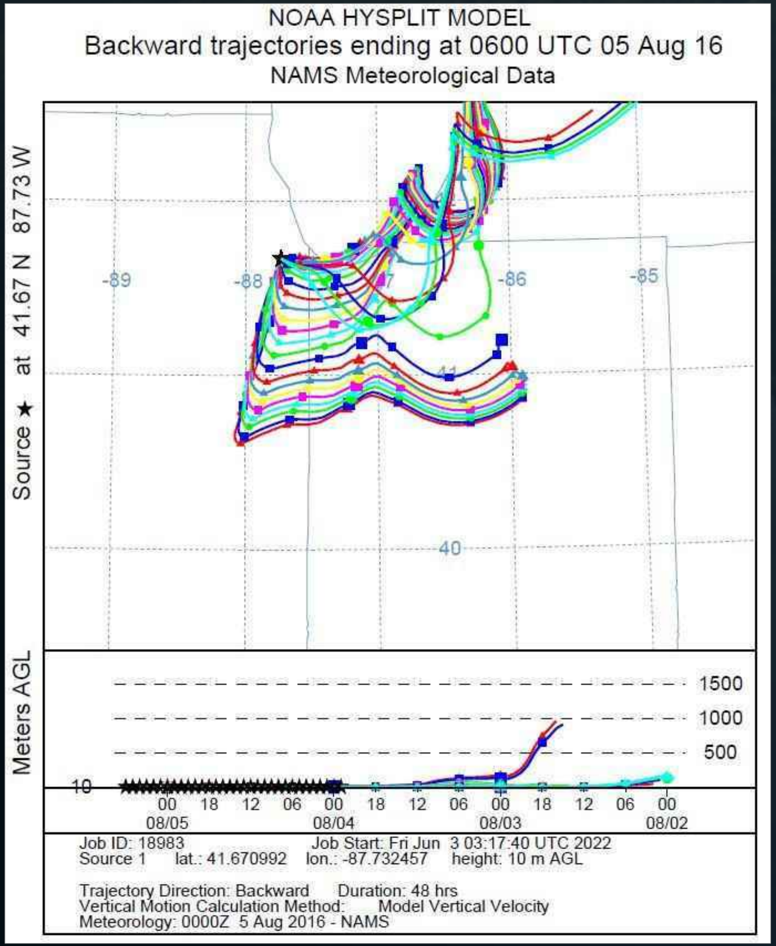
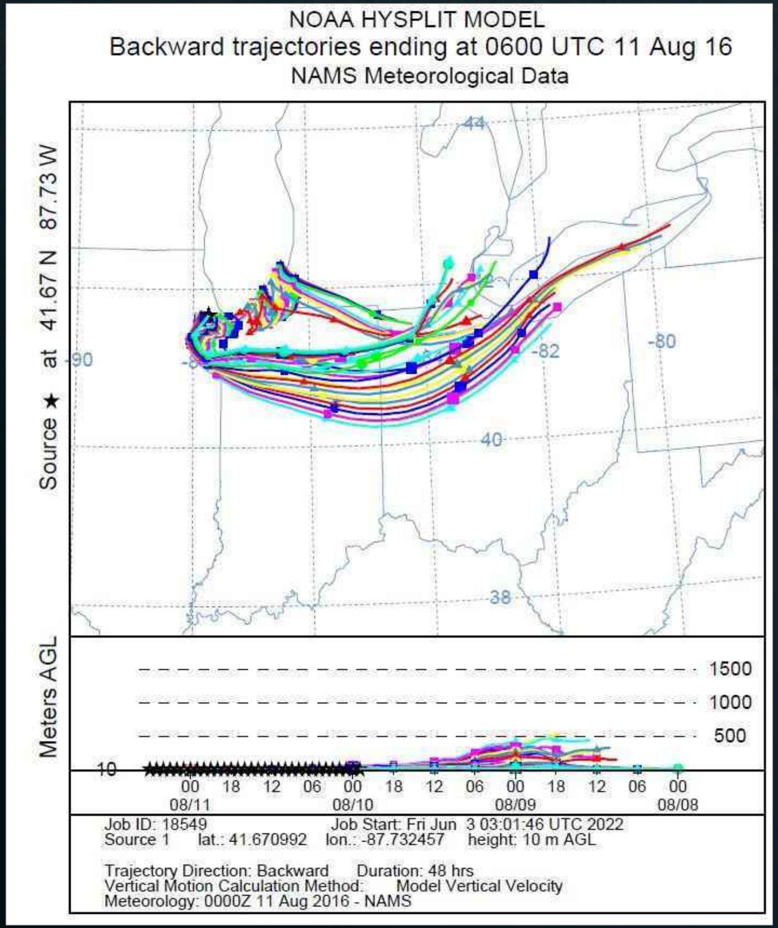


- Looking back 48-hrs from end of 8/4
- No likely MN contributions

Cook County, IL 17-13-0001/17-13-0076: August 10, 2016



- Looking back 48-hrs from end of 8/10
- No likely MN contributions

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN
ADDRESSING REGIONAL OZONE TRANSPORT FOR
THE 2015 8-HOUR NAAQS.

June 21, 2022

<u>EXHIBIT D:</u>

Trinity Consultants

COMMENTS ON EPA'S PROPOSED GOOD NEIGHBOR FIP

Docket EPA-HQ-OAR-2021-0668

US Steel

Prepared By:

TRINITY CONSULTANTS

June 21, 2022

Project 223901.0025

TABLE OF CONTENTS

LIST OF TABLES

EPA proposed a federal implementation plan (FIP) at 87FR20036 on April 6, 2022 to address interstate transport of oxides of nitrogen (NO_X) via the "good neighbor" provisions of the Clean Air Act. The *Good Neighbor FIP* proposal is an extension of prior EPA rulemakings that established the Clean Air Interstate Rule (CAIR) and multiple versions of the Cross State Air Pollution Rule (CSAPR). The following comments reflect the collective comments of Trinity and U.S. Steel with an emphasis on the feasibility of the control technologies proposed by EPA for the iron and steel industry.

1.1 General Comments

First, EPA's proposed emission limits for the iron and steel is completely separated from the approach to the Good Neighbor rule that EPA explains in the preamble (see also Section 1.1.2).

> *The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA proposes to include in this proposed rule, as well as the types of emissions control technologies on which the EPA proposes to base the emissions limitations that would take effect for the 2026 ozone season, generally* ***are intended to be consistent with the scope and stringency of RACT requirements*** *for existing major sources of NO_X in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.*
> 87FR20101-20102
>
> *The EPA recognizes that the numerous variables that contribute to differences in units' emissions rates may complicate development of limits for groups of units as large as those addressed in this proposed rule. For each emissions source category, the* ***EPA considered the range of emissions limits that currently apply to these sources under other CAA programs, such as RACT, NSPS, NESHAP, and OTC model rules, to develop an emissions limit that should be achievable by all sources after installing the controls identified in the Step 3 analysis.***
> 87FR20141
>
> *In developing the emissions limits for the Iron and Steel and Ferroalloy Manufacturing industry, the EPA reviewed RACT NO_X rules, NESHAP rules, air permits and related emissions tests, technical support documents, and consent decrees.*
> 87FR20145

The approach that EPA actually used in the proposed rule for the iron and steel industry is completely divorced from the stated rationale in the preamble. In the proposed rule:

- EPA started with the lowest emission rates identified in any prior RACT or BACT analysis
- EPA then applied additional reductions based on additional control technologies
- For iron and steel emission unit types other than annealing and reheat furnaces, the additional control technologies have never before applied to these emission units
- For most steel emission unit types other than annealing and reheat furnaces, EPA's references include no analysis of the feasibility of that control technology for that source type

For example, for annealing furnaces, EPA started with recent BACT determinations, and then applied an additional 40% reduction without any demonstration of achievability of the proposed limit. For blast furnaces, EPA started with an Ohio RACT limitation and then assumed a 50% reduction based on application of a control technology never before demonstrated to be feasible for this source type. EPA uses similar approaches for the proposed emission limits for all steel units in proposing emission limits far below those determined as either BACT or RACT in unit-specific analyses.

EPA appears to base its approach on an incorrect interpretation of the data in MCM and CoST and does not include any fact-based findings that these technologies can feasibly be implemented at the emission units in question. EPA had readily available fact-based steel specific analyses for these emission units that were completed in prior RACT, BACT, and BART determinations and yet ignored the fact-based determinations used to establish emission limits in those prior cases (see Section 1.2 for discussion of the fact-based unit-specific analyses previously completed by U. S. Steel, for example).

Second, the EPA rule development staff's apparent lack of knowledge or understanding of the iron and steel industry is illustrated throughout the proposed rule. For a vacuum degasser, NO_X is not generated in the process and so NO_X control cannot be applied there despite EPA's proposed control. And for an LMF, EPA proposes low NO_X burners as a control technology, but there are no burners in an LMF. If EPA wants to regulate NO_X from the steel industry, EPA must spend sufficient time to understand the process equipment and operations to develop an informed proposal rather than the current proposed rule.

Third, EPA does not provide actual citations or references to support most of the emission limits and proposed control technologies in the rules. As documented on a unit-specific basis in Section 1.2 as well as in Section 1.1.3, EPA does not include critical reference material in the docket for the rule, such that the regulated community cannot meaningfully review the proposed conditions.

Fourth, the proposed rule has numerous errors and inconsistencies. For example, the proposed rule suggests that the steel industry is subject to a 3-hour average in one location, and a 30-day rolling average in another location; the degree of stringency between a 3-hour and a 30-day average emission limit is well understood by EPA (see discussions in rulemakings for NSPS Subparts Da and Db for example). EPA also specifies applicability of the proposed rule in one location as any two units which combined exceed a PTE of 100 tpy, and in another location specifies applicability as on individual units over 100 tpy except in the BOF Shop, where emission units are added for applicability; again, the impact of the proposed rule will be substantially different depending on which applicability requirement applies.

1.1.1 EPA ignores stated control approach of RACT and does not justify its deviation from RACT

In all prior rulemakings for ozone transport, EPA has emphasized that the levels of emissions controls being required for EGUs was consistent with RACT. EPA has stated that the same approach is the underpinning for this present proposal.

> *The EPA notes that the types and sizes of the EGU and non-EGU sources that the EPA proposes to include in this proposed rule, as well as the types of emissions control technologies on which the EPA proposes to base the emissions limitations that would take effect for the 2026 ozone season, generally* ***are intended to be consistent with the scope and stringency of RACT requirements*** *for existing major sources of* NO_X *in downwind Moderate nonattainment areas and some upwind areas, which many states have already implemented in their SIPs.*
> 87FR20101-20102 [emphasis added]

The approach that EPA actually used in the proposed rule for the iron and steel industry is completely divorced from the stated rationale in the preamble and is more stringent than best available control technology (BACT)[1] or even lowest achievable emission rate (LAER)[2]. In the proposed rule, EPA started with the lowest emission rates identified in any prior RACT or BACT analysis, and then applied additional reductions, often based on control technologies never before applied to these emission units based on incorrect generic assumptions about viability without any support technical justification. For example, for annealing furnaces, EPA started with recent BACT determinations, and then applied an additional 40% reduction without any demonstration of achievability of the proposed limit. For blast furnaces, EPA started with an Ohio RACT limitation and then assumed a 50% reduction based on application of a control technology never before applied to this source type.

EPA uses similar approaches for the proposed emission limits for all steel units in proposing emission limits far below those determined as either BACT or RACT in unit-specific analyses. EPA never explains a rationale for deviating from RACT or BACT.[3]

> *Reasonably available control technology (RACT) means devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account:*
>
> *(1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard;*
>
> *(2) The social, environmental, and economic impact of such controls*
>
> [40 CFR 51.100(o)]

EPA's methodology in the proposed rule has significant flaws.

- BACT is a more stringent control level than RACT, and as such, by starting with BACT analyses, EPA is already selecting a control level that is more stringent than the stated rationale in the proposal preamble
- Compounding the first flaw, EPA then applies additional speculative reductions to each identified lowest emissions limits for each unit type, without any justification about the relevance of that control technology to the unit, nor any assessment of the percent control that may be achievable by that control

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1 *Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification* …
[40 CFR 52.21(b)(12)]

2 *Lowest achievable emission rate (LAER) means, for any source, the more stringent rate of emissions based on the following:*
(A) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or
(B) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within or stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance.
[40 CFR 51.165(a)(1)(xiii)]

3 The CoST/MCM has limited and generally poor data for the iron and steel industry. It appears that EPA incorrectly used CoST/MCM in a manner inconsistent with the referenced studies and documents on which CoST/MCM are based, and then attempted to "find" the reductions that CoST/MCM suggested may be available.

technology. Further, EPA is arbitrarily taking the lowest emission limit from the range of baseline NOx limits and applying the maximum percent reduction of the provided % NOx reduction efficiency range.

- EPA's method (and resulting emission limits for the iron and steel industry is actually more stringent than LAER. LAER is the lower of the most stringent limitation identified for a type of emission unit, or the lowest rate achieved in practice. EPA has not demonstrated that the emission rates in the proposed rule have been achieved in practice or are otherwise feasible, and the proposed rates are more stringent than any cited SIP emission limits.

1.1.2 EPA's apparent reliance on MCM and CoST to identify emissions control options for the steel industry is flawed

Nowhere in the preamble nor the rule docket does EPA identify a specific rationale regarding how EPA determined the applicability of a control technology to an emissions unit, nor how EPA determined what emissions reduction could be achieved on a unit. However, how EPA actually used MCM and CoST is deeply flawed.

As one example, for a blast furnace, EPA makes two statements in explaining the derivation of the proposed limit.

> *OH NO_X RACT rules limit NO_X emissions from blast furnaces to 0.06 lb/ mmBtu without requiring specific control technology. Control NO_X at stoves (typically 3 or 4 per blast furnace), assuming 40–50% reduction) by burner replacement plus SCR.*
> [87FR20145]
>
> *In setting a NO_X emission limit for blast furnaces, EPA considered a range of emission rates from 0.02 lb/mmBtu to 0.05 lb/mmBtu as calculated based on potential use of low-NOx burners, flue gas recirculation, and SCR. EPA notes that it has approved an Ohio SIP rule of 0.06 lb/mmBtu without specifically requiring use of NOx-reducing control technology. See OAC 3745-110-03(N). Use of these technologies separately or in combination can achieve 20-90% reduction efficiency at blast furnace stoves. In this rulemaking, EPA is requiring each facility to tailor its NOx reduction technology to meet a NOx limit of 0.03 lb/mmBtu.*
> [Non-EGU TSD]

So, EPA suggests that three control technologies are applicable here (low NO_X burners, FGR, and SCR) and stating that 20-90% NO_X reduction is achievable at blast furnace stoves using those technologies before proposing a 50% reduction on top of the Ohio NO_X RACT limit.

Despite being critical in supporting a proposed emission limit:

- EPA never states the basis for identifying that those three control technologies are applicable to blast furnaces
- EPA provides no explanation of why those measures are technically feasible for this application
- EPA provides no explanation of the impact on firing BFG versus natural gas versus a blend
- EPA provides no explanation regarding what reductions could be expected for a blast furnace,

From review of the non-EGU TSD, we infer that EPA is using the Menu of Control Measures (MCM) and the related Control Measures Database (CMDB) as reference sources for potential control technologies, as well as for cost effectiveness of potential control technologies.[4]

In connection with the preparation of these comments, Trinity downloaded the MCM section for iron and steel industry and reviewed both the MCM table entries as well as the cited references for the MCM; doing so required emails and phone calls to EPA staff quoted in the references to obtain files which are not in the rulemaking docket. Trinity also downloaded the Control Strategies Tool (CoST) and extracted the underlying data in the tool for steel, including the references.[5] Trinity also reviewed the CMDB.

Based on the review of these three sources, it is clear that CoST, MCM and CMDB rely upon the same input data sources to project potential control options and related control costs for the iron and steel industry. Trinity traced the iron and steel industry data listed in both MCM and CoST to the underlying cited reference files. Table 1 is a table showing the MCM and CoST references as well as the related steel references from EPA's non-EGU TSD. Table 1 also shows whether or not a reference was included in the docket for this proposed rule and whether or not Trinity was able to obtain references not included in the docket.

[4] https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation

[5] https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution

Table 1. References from EPA's MCM, CoST and non-EGU TSD

MCM Reference	CoST Reference	Non EGU TSD Reference	Reference	In Docket?	File obtained by Trinity
EPA 1993a	299		EPA, 1993: U.S. Environmental Protection Agency, Emissions Standard Division, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document-- NOx Emissions from Stationary Reciprocating Internal Combustion Engines," EPA,-453/R-93-032, Research Triangle Park, NC, July 1993.	N	Y
EPA 1993c	304		EPA, 1993: U.S. Environmental Protection Agency, Emissions Standard Division, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document-- NOx Emissions from Process Heaters," EPA-453/R-93-034, Research Triangle Park, NC, September 1993.	N	Y
EPA 1994e	308	34, 36, 43, 49, 50	EPA, 1994: U.S. Environmental Protection Agency, Emissions Standard Division, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document-- NOx Emissions from Iron and Steel Mills," EPA-453/R-94-065, Research Triangle Park, NC, September 1994.	Y	N/A
EPA 1998e	289		Pechan, 1998: E.H. Pechan & Associates, Inc., "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis," prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, Research Triangle Park, September 1998.	N	Y
EPA 2002a	283		EPA, 2002: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, "EPA Air Pollution Control Cost Manual," 6th ed., EPA/452/B-02-001, Research Triangle Park, NC, January 2002.	Y	N/A
EPA 2006b			"AirControlNET Database, May 2006" Prepared for US EPA, OAQPS, RTP, NC 27711. Prepared by Pechan & Associates, Inc., 5528-B Hempstead Way, Springfield, VA 22151. May 2006.	N	Attempted
EPA 2007b	277		"Control Measure Cost Calculation SummaryforNonEGUpointNOxcontrolsozoneRIA.xls" spreadsheet provided by Larry Sorrels (Sorrels.Larry@epamail.epa.gov) via email to Alison Eyth (eyth@unc.edu) 04-Sep-2007.	N	Y
EPA 2007d	280		EPA, 2007: U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards Health and Environmental Impact Division, Air Benefit-Cost Group "Regulatory Impact Analysis of the Proposed Revisions to the National Ambient Air Quality Standards for Ground-Level Ozone," EPA-452/R-07-008, Research Triangle Park, North Carolina, July 2007.	N	Y
EPA 2010b	205		EPA, 2010: "NOX CONTROL STRATEGIES IN THE IRON AND STEEL INDUSTRY (11-11-10).pdf", pdf document provided by Donnalee Jones (jones.donnalee@epamail.epa.gov) via email to Amy Vasu 11/16/10.	N	Y
ERG 2000	281		ERG, 2000: Eastern Research Group, Inc., "How to Incorporate the Effects of Air Pollution Control Device Efficiencies and Malfunctions into Emission Inventory Estimates," prepared for Emission Inventory Improvement Program, Point Sources Committee, July 2000.	N	Y
Pechan 2001			Pechan, 2001: E.H. Pechan & Associates, Inc., "Revisions to AirControlNET, and Particulate Matter Control Strategies and Cost Analysis," Revised Report, prepared for U.S. Environmental Protection Agency, Innovative Strategies and Economics Group, Research Triangle Park, September 2001.	N	Attempted
RTI 2011			RTI, 2011: "Evaluation of NOx Controls for Cupola Melt Furnaces", Jeff Coburn, RTI International, January 27, 2011	N	Attempted
Sorrels 2007	287		Sorrels, 2007: Larry Sorrels, Air Benefit and Cost Group, Office of Air Quality Planning & Standards, EPA, personal communication with Frank Divita, E.H. Pechan & Associates as documented in "Control Measure Cost Calculation SummaryforSCRsrevLS13007.xls," November 15, 2007 (via email).	N	Attempted
	285		EPA, 2001: U.S. Environmental Protection, Office of Research and Development, EPA, 2001: U.S. Environmental Protection, Office of Research and Development, EPA-600/R-01-087, Research Triangle Park, NC, October 2001.	N	Y
		35, 37, 39, 47, 48	Joint Research Centre of the European Commission, "Best Available Techniques (BAT) Reference Document for Iron and Steel Production," Industrial Emissions Directive 2010/75/EU (2013)	Y	N/A
		38	STAPPA/ALAPCO, Controlling Nitrogen Oxides Under the Clean Air Act: A Menu of Options, 78-79 (July 1994).	Y	N/A
		40	See Schreifels, Jeremy & Wang, Shuxiao & Hao, Jiming, Design and Operational Considerations for Selective Catalytic Reduction Technologies at Coal-fired Boilers, Frontiers of Energy and Power Engineering in	Y	N/A
		41	See EPA, Nitrogen oxides: Why and How they are Controlled, Clean Air Technology Center (MD-12), Technical Bulletin No. EPA-456/F-99-006R (1999), available at http://www. epa. gov/ttncatc1/dir1/fnoxdoc.pdf.	Y	N/A
		42	See Mukhtar, Umar Alhaji et al. "NOx Emission in Iron and Steel Production: A Review of Control Measures for Safe and Eco-Friendly Environment." Arid Zone Journal of Engineering, Technology and Environment 1	Y	N/A
		44	Midwest Regional Planning Organization (MRPO). 2005. Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis.	N	Y
		45, 46	Official Journal of European Union Commission, Best Available Techniques (BAT) Conclusions Under Directive 2010/75/EU of the European Parliament and of the Council on Industrial Emissions for Iron and Steel	N	Y
		51	EPA, Menu of Control Measures for NAAQS Implementation, available at https://www.epa.gov/air-quality-implementation-plans/menu-control-measures-naaqs-implementation (URL dated January 5, 2022).	N	Y
		52	See paragraph N, https://codes.ohio.gov/ohio-administrative-code/rule-3745-110-03	N	Y
		53	See https://docs.legis.wisconsin.gov/code/admin_code/nr/400/428/iv/20	N	Y
		54	See https://www.dep.pa.gov/About/Regional/NorthwestRegion/Community-Information/Pages/RACT-II.aspx	N	Y

Most of the reference files cited for MCM and CoST are re-compilations of earlier data. Based on Trinity's review of available files (either from the docket or obtained by Trinity during this review), the following documents are the most relevant ones for the iron and steel industry, listed by date. Summaries of these four documents are provided in Appendix A.

- EPA 1994e
  - A steel-specific analysis
  - U.S. Environmental Protection Agency, Emissions Standard Division, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document-- NOx Emissions from Iron and Steel Mills," EPA-453/R-94-065, Research Triangle Park, NC, September 1994.

- EPA 1998e
  - A first attempt by EPA at assessing non-EGUs with respect to ozone
  - Pechan, 1998: E.H. Pechan & Associates, Inc., "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis," prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, Research Triangle Park, September 1998.

- Non-EGU TSD Reference 44
  - Cited as an input to EPA2010b
  - Midwest Regional Planning Organization (MRPO). 2005. Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis, prepared by MACTEC

- EPA 2010b
  - The most recent steel-specific analysis by EPA
  - EPA, 2010: "NO_X CONTROL STRATEGIES IN THE IRON AND STEEL INDUSTRY (11-11-10).pdf", pdf document provided by Donnalee Jones (jones.donnalee@epamail.epa.gov) via email to Amy Vasu 11/16/10.
  - Trinity obtained two related additional files from EPA as part of our search for references
    - The 1994 Alternative Control Techniques document mentioned above
    - NO_X Control Technology from Iron and Steel Plants-05-03-10-send.pdf, which appears to be a peer review of the EPA 2010b document.

Among the documents, only two perform any analysis regarding steel industry units, (1) EPA 1994e, the 1994 Alternative Control Techniques (ACT) document, and (2) Non-EGU TSD Reference 44, the 2005 MRPO BART analysis. In contrast, EPA 1998e and EPA 2010b are data compilations but without any iron and steel industry unit analysis; each of EPA 1998e and EPA 2010b appear to be used by EPA to transfer data from the 1994 ACT and 2005 MRPO documents into EPA's MCM and CoST tools.

Critically important, the 1994 ACT and 2005 MRPO documents only assess NO_X emissions controls for reheat furnaces and annealing furnaces. Thus, the underlying studies for CoST only address two of the steel unit types proposed to be regulated in this EPA action. <u>As such, there is no basis in EPA's inclusion of emission limits for numerous other iron and steel emission units based on CoST and MCM, when CoST and MCM only have input data for annealing and reheat furnaces.</u>

1.1.3 The docket does not include critical reference files, and EPA must provide all references used in the docket in a future re-proposal

Based on statements in the preamble and the non-EGU TSD, EPA erroneously relied upon data compilations in MCM and CoST in determining that emissions reductions are available and cost effective from the iron and steel industry. However, MCM and CoST are simply compilations of other data sources, where the data for each control type and cost for process equipment are cited to an underlying document. Neither MCM nor CoST directly include explanations for how the included data are appropriate. As such, the underlying documents are critical to assessing the validity of the data.

Because EPA uses MCM and CoST as the basis for establishing the cost-effective emissions from the iron and steel industry (where cost effective reductions are those that EPA defines as contributing significantly), the accuracy of the underlying data is critical for a source to review the reasonableness of EPA's proposal.

As shown in Table 1, numerous key references in MCM, CoST and the non-EGU TSD were not included in the docket, and while Trinity was able to obtain some of the references that were sought, there were several which Trinity was not able to obtain, even in cases where the person cited in the reference was reached.

Beyond just MCM/CoST, there are other critical citations and/or documents not provided as part of the proposal for specific emission units. For example, for the EAF, EPA generically defines the baseline emissions as being based on comparison to existing permit limits for EAFs, without citing specific emission units and permit conditions. For coke oven charging, EPA references an apparently non-existent AP-42 emission factor but does not provide a citation. Where EPA is using a document as the basis for a proposed limit or condition, EPA must specifically identify the document and provide that document in the docket.

Due to the EPA not providing reference documents available for review, and due EPA's lack of citations/specificity in the basis for emissions limits, neither Trinity nor U. S. Steel cannot complete a thorough analysis.

1.1.4 EPA's cost estimates inaccurately assume year-round operation of control devices resulting in improperly low cost-effectiveness values

EPA's cost-per-ton reduction calculations are low because they assume that SCR will be run all year at facilities that install it and calculates expected cost per ton on the basis of annual tons of NOx reduced, despite the fact that the NOx emission reductions being sought by EPA in the Proposed Rule are only to address ozone season emissions. For instance, EPA estimates that selection of SCR in the iron and steel industry may be associated with 948 tons ozone season NO_X reductions, at an annual cost of $9,886,092. If EPA had calculated the cost per ozone season ton of NO_X reduced, this would result in a cost threshold estimate of $10,428 per ton of NO_X reduced[6], which is well above the cost threshold of $7,500 stated by EPA in the proposed rule). But EPA instead, lists the average cost per ton reduced as $4,345, which would only be the case if the ozone season tons were extrapolated to assume continuous annual reductions.[7]

While calculating cost effectiveness on an annual basis for comparisons can be appropriate, the correct cost basis for the proposed rule is on the ozone season. Under the proposed rule, EPA only has authority to reduce ozone season emissions and thus should limit itself to assessing the cost of ozone season reductions.

Additionally, as a practical matter, facilities will not operate SCR during the non-ozone season as EPA has acknowledged in the proposed rule to be "quite typical" in the context of EGUs. There are sound technical and economic reasons for not operating SCR outside the ozone season, due to the O&M cost associated with operation of the SCR. When comparing cost estimates to the $7,500/ton screening threshold set by EPA, the values must be compared on an ozone season basis.

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6 $9,886,092 / 948 ton = $10,428/ton

7 $9,886,092 / [12/5)*948 tons] = $9,886,092 / 2,275 tons = $4,345/ton

1.1.5 EPA's reliance on screening-quality emissions control data from CoST and MCM leads EPA to an incorrect conclusion on available reductions, and thus significant contribution

As noted in Section 6.1.1, EPA determined that emissions that could be removed below a certain cost threshold are those emissions which contribute significantly, regardless of the relative contribution by a state to a receptor. EPA then used CoST, MCM and the Control Measures Database (CMDB) to determine the emissions that could be removed based on theoretical application of SCR, SNCR and burner replacement.

> *Due to the many types of units within Iron and Steel Mills and Ferroalloy Manufacturing facilities that are not currently subject to NO_X limitations of the stringency necessary to eliminate significant contribution, most of the emissions limits in this proposed rule are based on examples of permitted emissions and estimated reduction potential from the identified control technology. Based on the selection of SCR, SNCR, and burner replacement in the non-EGU screening assessment, the EPA assumed reductions of 20 to 50 percent from current permitted limits and emissions tests depending on the type of unit and controls being implemented.*
> [87FR20146]

Note the key reliance on CoST, MCM and CMDB estimates, which are at best screening quality.

- In the quote above, EPA first states that units in the iron and steel industry are not subject to NO_X limitations sufficiently stringent to eliminate significant contribution.
- EPA has already stated that "significant contribution" is determined based on cost-effective reductions being available and EPA's discussion regarding Step 3.[8]
- To determine those cost-effective reductions are available, EPA relied upon CoST, as when a CoST model run was completed, the CoST modeling showed that emission reductions are available in the steel industry that are cost effective
- Upon the CoST run showing that cost effective reductions are available in steel, EPA then relied upon CoST/MCM/CMDB to identify potential control technologies that could be applied to the steel industry units
- Lastly, EPA appears to have arbitrarily selected % reductions from the lowest identifiable emissions rate for a steel unit based on some unstated attribution to a mix of add-on controls identified by MCM as being applicable (see Table 2)

EPA also made assumptions about the types of emission units at which the control technologies were feasible without any stated basis. None of the underlying technical analyses support add-on pollution control on any steel sources other than annealing furnaces, while the proposed rule covers numerous additional steel emissions units. Trinity infers that EPA may have been misled by data in CoST and MCM regarding the applicability of the control measures.

[8] As per 87FR20055, *the EPA selected the technology breakpoint (represented by a cost threshold) that, in general, maximized cost-effectiveness—i.e., that achieved a reasonable balance of incremental NOX reduction potential and corresponding downwind ozone air quality improvements, relative to the other emissions budget levels evaluated. See, e.g., 81 FR 74550. The EPA determined the level of emissions reductions associated with that level of control stringency to constitute significant contribution to nonattainment or interfere with maintenance of a NAAQS downwind.*

Moreover, EPA never attempts to justify why case-specific recent BACT and RACT determinations (cited as the basis for the lowest identifiable emission rates) are not more reliable and accurate than screening level, generic data from CoST and MCM.

Table 2 summarizes EPA's proposed steel unit emission limits, as well as EPA's stated rationale for the limits from both the rule preamble as well as from the non-EGU TSD. The non-EGU TSD references MCM as the basis for the potential control percentages, and the preamble references CoST, but since MCM and CoST have largely the same underlying references the distinction in MCM versus CoST is minor.

EPA correctly notes the limitations of CoST in a footnote to Table IX-2 in the proposal (87FR20157), but then ignores this critical caveat in the proposed rule.

> *CoST is designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have emissions reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units. … This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs.*

The author of the footnote to Table IX-2 understood the limitations of using CoST (which in turn relies upon both MCM and CMDB). However, in the proposed requirements, EPA ignores the limitations of CoST. In the proposed rule, EPA presumes that CoST is accurate and applicable to each and every steel emissions unit, without any consideration of a feasibility assessment or any engineering.

Table 2. EPA assumptions underlying proposed steel limits

Emissions Unit	Proposed Limit	Units	Add-On	% Reduction	EPA Basis from Preamble	EPA Basis from non-EGU TSD
Blast Furnace	0.03	lb/ MMBtu	Burner replacement/ SCR	50%	OH NOX RACT rules limit NOX emissions from blast furnaces to 0.06 lb/ mmBtu without requiring specific control technology. Control NOX at stoves (typically 3 or 4 per blast furnace), assuming 40–50% reduction) by burner replacement plus SCR.	In setting a NOx emission limit for blast furnaces, EPA considered a range of emission rates from 0.02 lb/mmBtu to 0.05 lb/mmBtu as calculated based on potential use of low-NOx burners, flue gas recirculation, and SCR. EPA notes that it has approved an Ohio SIP rule of 0.06 lb/mmBtu without specifically requiring use of NOx-reducing control technology. See OAC 3745-110-03(N). Use of these technologies separately or in combination can achieve 20-90% reduction efficiency at blast furnace stoves. In this rulemaking, EPA is requiring each facility to tailor its NOx reduction technology to meet a NOx limit of 0.03 lb/mmBtu.
Basic Oxygen Furnace	0.07	lb/ton	SCR/SNCR	50%	Potential 25–50% reduction by SCR/SNCR from 0.14 lb/ton based on emissions testing.	For basic oxygen furnaces, EPA based the emission limit of 0.07 lb/ton of steel on performance testing data from basic oxygen furnaces without NOx reduction controls at integrated iron and steel mills in the United States. EPA projects minimally 50% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of FGR and selective catalytic reduction. Most BOF vessels and associated BOF Shops in the United States are equipped with capture technology and existing particulate matter control devices. The existing configurations of these shops would accommodate the addition of NOx controls or additional design of a capture system capable of integrating such technology with these structures.
Electric Arc Furnace	0.15	lb/ton steel	SCR	25%	Example permit limits at around 0.2 lb/ton. Assumes 25% reduction by SCR to achieve 0.15 lb/ton steel.	For EAFs, EPA based the emission limit of 0.15 lb/ton of steel on projected reduction efficiency of 40-50% as compared to existing permit limits for EAFs. EPA considered a range of baseline emission data and permit limits from mini mills, integrated iron and steel facilities, and ferroalloy facilities ranging from 0.20 lb/ton to 0.35 lb/ton. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of low-NOx burners and selective catalytic reduction.
Ladle/tundish Preheaters	0.06	lb/ MMBtu	SCR	40%	Nucor Kankakee BACT permit limit issued January 2021 is 0.1 lb/mmBtu, 2021. Assume 40% reduction by SCR.	For ladle and tundish preheaters, EPA based the emission limit of 0.06 lb/mmBtu on existing permit limits. The majority of recently issued permits limit NOx emissions from ladle and tundish preheaters to 0.1 lb/mmBtu based on prevailing operating rates compared to natural gas usage. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of low-NOx burners and selective catalytic reduction.
Reheat furnace	0.05	lb/ MMBtu	SCR	40%	Sterling Steel permit, issued 2019: Low-NOX natural gas fired burners de- signed to emit no more than 0.073 lb NOX/mmBtu, Ohio RACT limit is 0.09 lb/mmBtu. Assume 40% reduction by SCR.	For reheat furnaces, EPA based the emission limit of 0.05 lb/mmBtu on projected reduction efficiency of 40-50% based on sampled operating and emission rates compared to natural gas usage. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of newer generation low-NOx burners or optimization of existing burners.
Annealing Furnace	0.06	lb/ MMBtu	SCR	40%	Big River Steel (AR) 2018 limit and Benteler Steel (LA) 2019 limit (0.11 lb/ mmBtu), 85 mmBtu/hr and 13 mmBtu/hr, respectively. Lowest was 0.0915 lb/mmBtu, Nucor AR. Assume 40% reduction by SCR.	For annealing furnaces, EPA based the emission limit of 0.06 lb/mmBtu on projected reduction efficiency of 40-50% based on current permit emission limits and operating rates compared to natural gas usage. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of newer generation low-NOx burners or optimization of existing burners, or combination of low-NOx burners, flue gas recirculation, and/or selective catalytic reduction.
Vacuum Degasser	0.03	lb/ MMBtu	SCR	40%	0.05 lb/mmBtu Nucor Darlington (SC) and Nucor Tuscaloosa (AL). Assume 40% reduction by SCR.	For vacuum degassers utilized in secondary steelmaking, EPA based the limit of 0.03 lb/mmBtu on existing permit limits of 0.05 lb/mmBtu. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including use of selective catalytic reduction.
Ladle Metallurgy Furnace	0.1	lb/ton	SCR	40%	Assume 40% reduction by SCR.	For LMFs, EPA based the emission limit of 0.1 lb/ton of steel on projected reduction efficiency of 40-50% as compared to existing permit limits for LMFs. EPA considered a range of baseline emission data and current permit limits from 0.20 lb/ton to 0.35 lb/ton. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx technology, including potential use of low-NOx burners and selective catalytic reduction.
Taconite Production Kilns	tice, low NOx burners				Consistent with requirements in Minnesota Taconite FIP See 81 FR 21671.	
Coke Ovens (charging)	0.15	lb/ton of coal charged	Staged combustion SCR/SNCR	50%	Assume 50% reduction staged combustion and/or limited use SCR/SNCR during charging operations from AP–42 0.3 lb/ton emission factor.	For coke ovens (charging) and coke ovens (pushing), EPA based the emission limit of 0.15 lb/ton for charging and 0.015 lb/ton for pushing on projected reduction efficiency of 40-50% based on current permit emission limits and production-based push/charge cycles. EPA projects minimally 40% NOx reduction efficiency is achievable by use of low-NOx practices, staged pushing and hood configurations, and potential use of add-on NOx control technology at larry cars and pushing/charging machines, including potential use of low-NOx burners, flue gas recirculation, and/or the addition of selective catalytic reduction to mobile hoods and particulate matter control devices.
Coke Ovens (pushing)	0.015	lb/ton of coal pushed	SCR	25%	SunCoke Middletown limit is 0.02 lb/ton of coal. Assume 25% reduction by SCR.	

1.1.6 The lack of a trading option makes EPA's errors in setting unit-specific emission limits critical

In prior Good Neighbor rulemakings focused on EGUs, EPA has had reasonably accurate cost estimates for emissions control for EGUs in the aggregate. For EGUs, as long as EPA is reasonably accurate, the availability of an emissions trading program provides unit-specific flexibility. If a control technology at a particular unit is much more expensive, that unit has the option to buy allowances and comply with the regulations. Or, alternatively and more likely, a company may choose to over control one source that is more cost effective to generate allowances for another source that is less cost effective.

For two reasons, EPA's approach with non-EGUs suffers critical flaws. First, as already explained earlier in this section, EPA's cost estimates are screening level only, and it appears that EPA selected the lowest published cost estimates from the available studies (with no stated basis for that selection); that in itself brings question on EPA's proposed emission limits.

Because each emissions unit must meet a specific emissions limit, with no opportunity to trade allowances either within the company or in the greater market, the accuracy of the cost estimates becomes a critical factor. Unquestionably EPA's cost estimates are inaccurate for the proposed emissions sources, and unquestionably as proposed each unit must meet a specific emissions limit based on screening, highly caveated analysis, where that analysis has zero technical foundation for emission units other than reheat and annealing furnaces.

1.1.7 EPA has incorrectly applied its own data to a determination of the cost threshold to evaluate emission reductions related to Tier 1 industries

As noted earlier, there are numerous problems with the assumptions in EPA's CoST model with respect to the steel industry. Beyond those problems, EPA incorrectly applied its own CoST output data regarding emissions reductions from Tier 1 industries.

In EPA's Screening Assessment for Non-EGU Emissions Units, EPA states the following:

> *To identify an annual cost threshold for evaluating potential emissions reductions in the Tier 1 and Tier 2 industries, the EPA used the Control Strategy Tool (CoST), the Control Measures Database (CMDB), and the projected 2023 emissions inventory to prepare a listing of potential control measures, and costs, applied to non-EGU emissions units in the projected 2023 emissions inventory. Using this data, we plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments. Figure 1 indicates there is a "knee in the curve" at approximately $7,500 per ton. We used this marginal cost threshold to further assess estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries. Note that controls and related emissions reductions are available at several estimated cost levels up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.*

A review of Figure 1 in the document shows that that Tier 1 Industries have a very much lower marginal cost threshold than the $7,500 per ton value assigned to Tier 1 Industries by EPA. Indeed, as is graphically illustrated in Figure 1, the knee in the curve for Tier 1 sources occurs at a cost of approximately $1,000 per ton at which point the ozone season NO_X reduction potential is in excess of 50,000 tons. Increasing the cost threshold to $7,500 per ton (approximately a 700% increase in cost) does nothing more than increase the

Tier 1 NO_X reduction potential by approximately 15% more than would be achieved at the $1,000 per ton threshold. The CoST model is showing is that nearly all available reductions at Tier 1 industries are at the $1,000/ton level; based on review by Trinity of the CoST inputs for the steel industry, CoST reductions at less than $1,000/ton correlate only to combustion improvements like low NO_X burners, and not to post-combustion controls like SCR.[9]

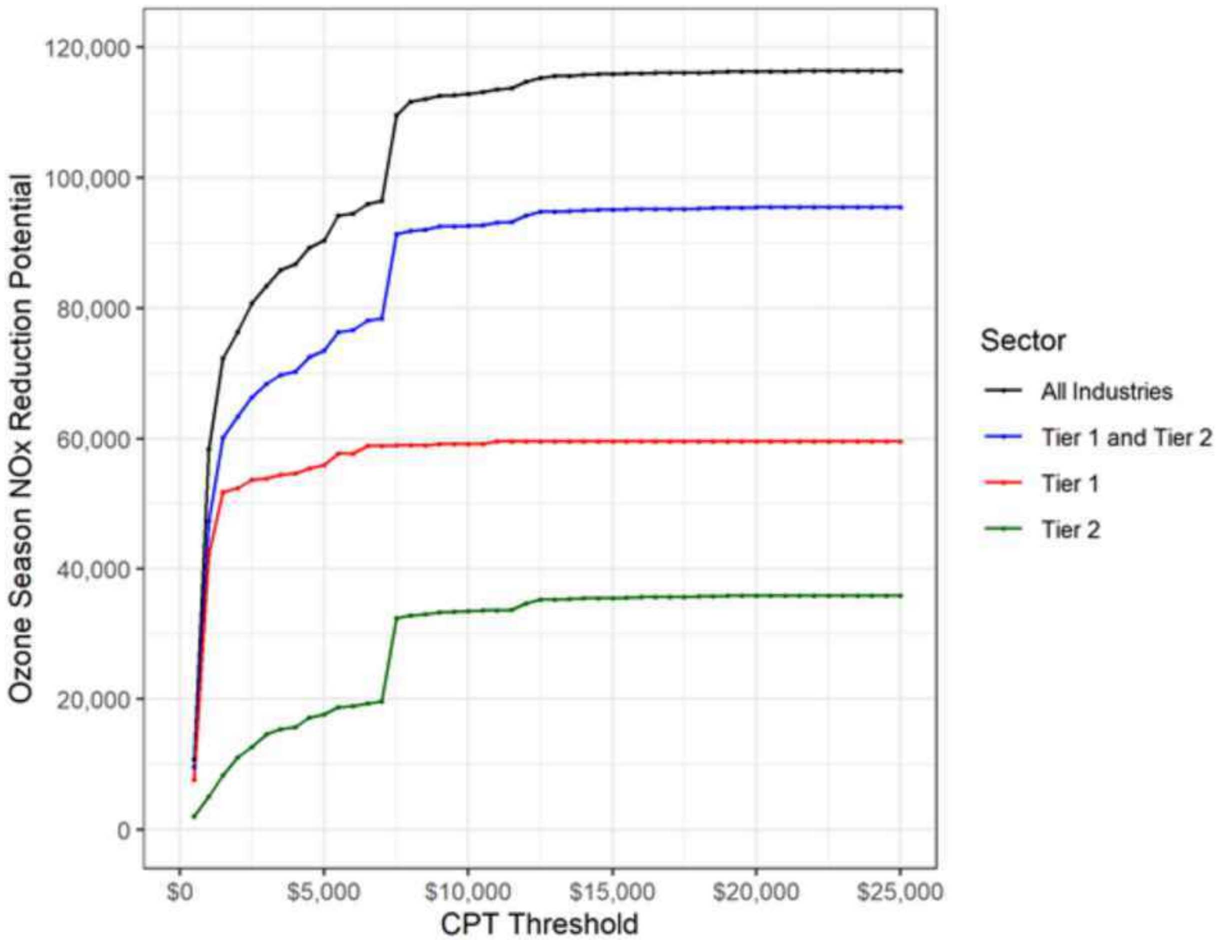
In prior rulemakings, EPA has emphasized the importance of identifying the knee in the curve to optimize cost efficiency. In the present rulemaking, EPA discusses exactly this topic in the context of not increasing the cost threshold for EGU control costs.

> *Emissions reductions from these measures are relatively small and would entail much higher dollar per ton costs, going beyond what is widely observed in the fleet. Although these additional measures are not included in EPA's technology breakpoint analysis discussed above, the EPA did examine the cost, potential reductions, and air quality impact of these additional measures in a supplemental analysis to affirm that they do not merit inclusion in the proposed stringency for this action. Similar to prior rules, there is a notable "knee-in-the-curve" breakpoint if these additional measures are included in EPA's analysis. In other words, there are very little additional emissions reductions and air quality improvement at problematic receptors, and the cost associated with these measures increases substantially on a dollar per ton basis.* [87FR20095]

The exact case that EPA describes here for EGUs applies to Tier 1 non-EGUs when extending the $/ton threshold beyond approximately $1,000/ton: based on CoST predictions, minimal additional emission reductions are obtained from Tier 1 industries going beyond $1,000/ton, and yet costs increase substantially.

[9] While SCR is not a post-combustion control as applied to an EAF and other emission units in the iron and industry industry where NOx emission are not generated by combustion of fossil fuels, we refer to them here as post-combustion controls because that his how EPA refers to SCR and other technologies in the proposed rule.

Figure 1. Ozone Season NOx Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and Other Industries



1.2 Analysis of Feasibility of Proposed Limits and Theoretical Controls

As discussed in more detail below, EPA has failed to demonstrate that the proposed emission limits for the iron and steel industry and theoretical controls in the proposed rule are technically feasible.

1.2.1 Blast furnaces

1.2.1.1 Description

Blast furnaces (BFs) are used to convert iron ore and iron-bearing raw materials to hot metal. The process is completed in a vertical shell blast furnaces in which raw materials (ore, coke, and flux) are introduced at the top of the furnace and hot blast air, oxygen and either natural gas, pulverized coal or coke oven gas are injected at the bottom of the furnace to generate heat and melt the iron by removing the oxides to form metallic iron.

To provide the hot blast air, the furnaces are equipped with regenerative heat exchangers (stoves) in which the blast air is preheated. Blast furnace gas (BFG) and natural gas (and if available cleaned desulfurized coke oven gas (COG)) are fired in the stoves to heat the stove refractory. When the required temperature is achieved the gas flow is reversed and the stored sensible heat is recovered into the blast air. Typically, there are 3 to 4 stoves (dependent on age and design) on each blast furnace which allows a continuous and even blast air temperature with one common exhaust stack per set of stoves; note that the stove stack exhaust is separate and distinct from the off-gases produced from the iron-making process in the blast furnaces.

Combustion of BFG, in general, but in particular on the stoves, requires a high volume of combustion air due to a significant percentage of inert gases in the BFG (CO_2, N_2). The combustion produces thermal NO_X, but the reaction is suppressed by the presence of CO in the combustion flame and emits much less thermal NO_X than does natural gas combustion (COG emits thermal NO_X at a rate between that of BFG and natural gas). As in all combustion reactions excess oxygen and flame temperature determine NO_X formation, and the BFG with smaller heating value, approximately 1/10 of natural gas, burns at relatively low adiabatic flame temperature.

Typical stoves have exhaust temperatures in the 350-500 °F range, with emission rates already in less than typical low NO_X emission rates for boilers.

1.2.1.2 Potential for NO_X Reduction

NO_X reductions could be achieved on a blast furnace process in the event any of the following technologies were technically or economically feasible

1. Use of lower NO_X burners in the stove heating system.
2. Installation of selective catalytic reduction (SCR) in the stove stack(s).
3. Flue gas recirculation.
4. Selective non-catalytic reduction (SNCR) in the stove stacks .

U. S. Steel evaluated RACT for blast furnace stoves at Edgar Thomson in a report by AMEC Environmental and Infrastructure dated April 1, 2014. The analysis at this site is representative of blast furnace stoves in the U. S. Steel fleet.

The 2014 RACT analysis found the following:

- Units were achieving NO_X emission rates of less than low NO_X emission rates for boilers

- Flue gas recirculation (FGR) is not technically feasible since blast air cannot be recycled from the blast furnace and air flow during initial heating of the stoves is based on natural convection

- SCR
  - Determined to be technically infeasible due to the changing direction of the air flow, such that there are substantial temperature swings as a stove switches from heat to blast and back.
  - Determined to cost from $75,533/ton to $124,972/ton assuming for the sake of argument that SCR was actually technically feasible
- SNCR
  - Technically infeasible like SCR due to temperature swings
  - More costly than SCR at $426,000/ton to $678,001/ton

U. S. Steel also evaluated BART for blast furnace stoves at Gary Works in a September 25, 2020 analysis by Barr. That analysis found that no add-on technology was BART for the stoves, and that BFG was already a low NO_X fuel

1.2.1.3 EPA's Proposed Emission Limit for Blast Furnaces is Not Feasible

- EPA's assumption of a 50% reduction in NOx emissions from blast furnaces using add on-control technologies is not supported by any technical analysis for blast furnace stoves
- There is no technical analysis in the docket or in references used as the basis for CoST and MCM for blast furnace stoves.
- EPA has erroneously found that cost-effective emission reductions are available at blast furnace stoves by misusing the EPA CoST model
- EPA incorrectly assumes that SCR is applicable to blast furnace stoves despite any support in the docket
- The underlying EPA SCR cost estimates for iron and steel units only have any basis for annealing and reheat, where costs are developed in the 2005 MRPO BART document
- EPA's CoST model only cites two bases for SCR costs for steel process units $7,020 (2016$) for SCR for an annealing furnace, and $6,599 (2016$) for coke oven gas in-process combustion (by citing here, Trinity and U. S. Steel do not concur that EPA's CoST model SCR costs are correct)
  - The annealing estimate is cited on #280, #283, #285, #287, #289 and #304
  - The coke oven gas estimate is cited as #205 and #277 (discussed above)
    - #280 is a 2007 regulatory impact analysis that did not perform a cost estimate specific to steel units but instead used standard CoST/MCM/CMDB data in a screening analysis for non-EGU emissions
    - #283 is the EPA Control Cost Manual that only instructs how to perform economic calculations
    - #285 is about SCR costs on coal-fired boilers
    - #287 was not obtainable despite contact with to the EPA
    - #289 is an analysis performed as part of the NO_X SIP Call that first attempted to assess non-EGU impacts, but did not perform any analyses specific to steel units

- #304 is an EPA document about process heaters overall, focusing on chemical and petroleum refining, with no analysis of steel process heaters and no analysis of the BFG or COG
- The only underlying studies that attempted to calculate steel costs for SCR are the 1994 ACT study and the 2005 MRPO study
- The 2005 MRPO study values (in 2005$) for SCR range from $7,566-$13,762 for annealing furnaces, with numerous caveats about the generic assumptions and how site-specific variations could result in substantial cost or feasibility differences
- The EPA CoST model lists a cost (in 2016$) for SCR of $7,020 for annealing furnaces and $6,599 for coke oven gas. These values are below the lowest value from the 2005 MRPO study, prior to adjusting the 2005 MRPO values to adjust to 2016$.
- Annealing and reheat furnaces are vastly different processes than blast furnace stoves.
- Overall, the $/ton cost effectiveness values for SCR for iron and steel emission units in the CoST model are not credible and not supported by the underlying reference documents

1.2.2 Basic Oxygen Furnace

1.2.2.1 Description

Basic oxygen furnaces (BOFs) are used in integrated iron and steel facilities to convert hot metal produced in the blast furnace and scrap to steel. In order to convert the hot metal to steel, the carbon in the hot metal is removed by oxidation in the BOF vessel. This process is completed by blowing oxygen into the liquid metal bath forming carbon monoxide (CO) and carbon dioxide (CO_2) and slag by the addition of flux (quick lime). The oxidation of carbon generates heat which melts the scrap, and raises the liquid temperature to about 2,800°F. The CO and CO_2 produced are emitted from the vessel with a significant concentration of particulate matter which must be removed to meet the MACT particulate emission limits. The blowing process does not generate NO_X due to the complete reaction of oxygen (O_2) with the carbon in the hot metal without nitrogen (N_2) gas in the vessel (the lack of nitrogen gas (air) in the vessel prevents any possibility of forming NO_X within the molten metal – the only gases present include the O_2 being injected and CO and CO_2 being emitted, as all O_2 is consumed). At the vessel exit the gases are typically about 3,200˚F.

The BOF blowing process occurs in batch cycles with charging, blowing, and tapping events. The total cycle can be one hour with the oxygen blowing period lasting approximately 20 minutes. Off-gas temperatures entering the capture hood can be between 350 °F during charging and 3,200 °F during the peak blow of the heat cycle. U. S. Steel operates with the open-hood designs which includes full combustion of off-gases.

The full combustion operation captures the off-gases in an open hood. Ambient air is introduced between the vessel mouth and hood. The amount of air introduced is controlled by the system draft to prevent fugitive emissions and assure combustion of CO and hydrogen (H_2) emitted from the vessel. As a result of the off-gas combustion, the gas temperature increases to about 3,800 °F and NO_X can be formed as thermal NO_X. The gases are cooled by convection/radiation in the specially designed water- cooled hood and direct water spray evaporation. Gases are cooled to about 450-550° F and introduced to a cold side electrostatic precipitator (ESP) or wet scrubber for particulate removal. The particulate emitted from the furnaces is abrasive consisting of oxide forms of iron and other metals. The gas temperature and moisture content are critical for proper ESP operation. U. S. Steel operates four BOF vessels with two ESP control systems. There are 10 BOF vessels operated with five venturi scrubbers for particulate removal.

NO_X formation over the blow cycle is variable in the primary hood due to the constantly changing off-gas temperature profile and oxygen content of the gases due to hood draft requirements needed for compliance with NESHAP Part 63 Subpart FFFFF. In addition, no two heats are identical due to metal chemistry (percent carbon in hot metal (HM), silica content, etc.). The presence of carbon monoxide inhibits NO_X formation and the carbon burn rate (lb/min) during the blow period changes the CO/CO_2 percentage of the gases.

1.2.2.2 Potential for NO_X Reduction

The application of NO_X control technology before particulate removal is not feasible for these process units due to the cyclic nature of the process and presence of metallic particulate matter in the gas stream that will poison SNCR or SCR media.

In addition, the temperature in the primary hood is variable over the blow period and the required gas temperature/residence time for SNCR function cannot be achieved. Further, the required molar ratio for ammonia introduction for the NO_X ammonia reaction would be extremely difficult to meet (and potentially impossible) due to the rapidly varying NO_X formation.[10] There is no place to install an SNCR. There are no SNCR in operation across the industry. EPA hasn't provided any demonstration that SNCRs are technically feasible.

For SCR application similar conditions apply. Overall, the gases are too hot and with widely and rapidly variable temperatures, which negates the ability to use tempering air or water injection to meet the required SCR temperature (and additionally such injection may result in inappropriate conditions for proper ESP operation). Additionally, the metallic particulate will rapidly deteriorate the catalyst and poison the noble metals if used upstream of the particulate control device. Thus, an SCR pre-gas conditioning and cooling is not feasible for BOFs.

SCR could be theoretically applied after the particulate removal in the ESP or scrubber, but the BOF exhaust temperatures are only approximately 90 to 130 degrees; therefore, gases would require substantial reheating to the required SCR reaction temperature between heats and during the heat cycle requiring increased natural gas combustion, which would generate additional NO_X and Greenhouse Gases (GHGs). Further, to prevent rapid thermal degrading of the SCR catalyst, the catalyst bed would be required to be held at the operating temperature between heats, producing even more additional NO_X and GHGs. For BOFs, there are no SCRs in operation across the industry. EPA hasn't provided any demonstration that SCRs are technically feasible.

U. S. Steel evaluated RACT for BOF at Edgar Thomson in a report by AMEC Environmental and Infrastructure dated April 1, 2014. The analysis at this site is representative of BOF in the U. S. Steel fleet.

The 2014 RACT analysis found the following:

- Low NO_X burners are not technically feasible as no burners are present
- Flue gas recirculation is not technically feasible as the furnace does not operate on an air/fuel ratio basis, but instead based on high pressure oxygen lancing
- SNCR is potentially technically feasible with heating of exhaust gas, but would cost $1,143,618/ton (2014$)
- SCR is potentially technically feasible with heating of exhaust gas, but would cost $222,562/ton (2014$)
- Due to the large volume of airflow (~250,000 acfm at ~125 °F), the NO_X concentration would be extremely low and likely below the lower range concentrations to be treated by SCR

[10] One cannot monitor the pre-SNCR NO_X levels and the only available control input is the downstream NO_X levels, which cannot achieve the fine time resolution required to match the molar limit (an analogy would be driving a car through curves via using only the rearview mirror).

1.2.2.3 EPA's Proposed Limits are Not Feasible

U. S. Steel is not aware of any technically feasible NO_X control methods applicable to BOF vessels. In the non-EGU TSD, EPA incorrectly states that there is a BOF NOx emission limitation of 0.1 lb/MMBtu contained in the Ohio NO_X RACT rules. The Ohio NO_X RACT limit described in Rule 3745-110-03(N) applies to No. 1 and No. 2 BOF ladle preheaters, not the BOF.

EPA does not cite a basis for the 0.14 lb/ton reference value and cannot use an un-cited value as the basis for an emission limit. Instead, EPA only generically refers in the non-EGU TSD to

> *performance testing data from basic oxygen furnaces without NOx reduction controls at integrated iron and steel mills in the United States*

Because EPA does not cite a basis for the 0.14 lb/ton emissions level, it is not possible to review the validity of that value, nor the operating conditions under which that value was obtained. Without such documentation, EPA cannot use the 0.14 lb/ton value as the basis for an emissions limit. EPA states that there is a potential 25-50% reduction based on SCR/SNCR at the BOF, and then arbitrarily uses the upper 50% to reduce the undocumented 0.14 lb/ton value to the proposed limit of 0.07 lb/ton.

1.2.3 Electric Arc Furnaces

See the Black & Veatch Report and the discussion in U.S. Steel's comment letter for a discussion of the feasibility of control technology for electric arc furnaces.

1.2.4 Ladle/Tundish Preheaters

1.2.4.1 Description

Ladle and tundish preheaters are employed in the steel shop to dry out the ladle and tundish refractory prior to use in the steel making process after ladle repairs and to preheat the ladles and tundishes so as not to "shock" the ladle or tundish prior to hot metal or liquid steel being added. Drying out the ladles prior to use is done to prevent steam release during metal addition, which is a serious safety concern for the industry. Preheaters are also used to cure refractory after repair. Note that tundishes are only at caster facilities and are not part of a BOF Shop.

In both applications, an open gas flame is introduced into the ladle/tundish to increase the refractory temperature. The equipment is typically an air/fuel burner in a vertical (down-fire) position or horizontal position depending on the heater manufacturer. The heat input of the burner is small with multiple ladle/tundish positions. The emissions are categorized as fugitive emissions as there is no stack or control point associated with these processes.

The gas burners are very small with heat inputs of typically 5-15 MMBtu/hr. When vertically fired a cover is placed over the ladle through which the burner fires into the ladle space to keep the heat within the ladle. Combustion gases are vented through the gap under the cover via natural draft.

1.2.4.2 Potential for NOx Reduction

Gas burners can be retrofitted to a low NO_X design and some manufacturers offer low NO_X burner packages; however, emissions from these processes are low and do not meet the 100 tons per year applicability threshold either individually or combined site wide unless aggregated with the BOF Shop NOx emissions as in EPA's proposal. Therefore, the NO_X emissions reductions from ladle preheaters would also be minimal.

The use of selective non-catalytic reduction (SNCR) would be technically infeasible due to no stack or existing emissions collection systems. Also SNCR would be technically infeasible without preheating since the gas exhaust temperatures are too low for proper operation.

Practically speaking, SCR is not technically feasible on these units. SCR would require a movable hood emissions collection system, a stack, and reaction chamber, as the exhaust is not currently contained after leaving the ladle/tundish.

SCR would require significant gas reheat of a large air stream downstream to be potentially viable. Based on the above flow rates, the cost effectiveness of SCR would be at best $62,036/ton (2021$) as calculated by Trinity for a 9 MMBtu/hr unit assuming that a sufficiently tight hood could be constructed to only result in 10x the stoichiometric air flow rate, and not counting any costs for designing and constructing a hood.

1.2.4.3 EPA's Proposed Emission Limit is Not Feasible

The base case 0.1 lb/MMBtu limit is from a 2021 BACT analysis, and is the lowest possible emission rate that could be identified as RACT**.** SCR is questionably technically feasible and not cost effective. EPA's assumption of a 40% reduction using add on-control technologies is not supported by any technical analysis for a ladle preheater – there is no technical analysis in the docket or in references used as the basis for CoST and MCM for ladle preheaters. EPA has erroneously found that cost-effective emission reductions are available at a ladle preheaters by mis-using the EPA CoST model. See discussion on blast furnace stove references.

1.2.5 Reheat Furnaces

1.2.5.1 Description

Reheat furnaces are large furnaces used to raise the temperature of steel slabs through direct firing of natural gas and/or coke oven gas to process steel stabs to a temperature suitable for hot working and shaping. They are designed to accommodate the steel slabs being processed at a suitable design rate, heat it uniformly, and hold it at a desired temperature for a specified length of time.

1.2.5.2 Potential for NO_X Reduction

U. S. Steel evaluated RACT for a reheat furnace at the Irvin Plant in a report by AMEC Environmental and Infrastructure dated April 1, 2014. The analysis at this site is representative of reheat furnaces in the U. S. Steel fleet.

The 2014 RACT analysis found the following:

- SCR
  - Technically infeasible due to the failed application at a similar facility (inconsistent reductions, frequent SCR system degradation, high ammonia slip)
  - Economically infeasible even if technical challenges could be overcome at $18,764/ton (2014$)
- SNCR
  - Technically infeasible
  - Economically infeasible even if technical challenges could be overcome at $145,702/ton (2014$)

U. S. Steel additionally evaluated reheat furnaces for BART in a September 25, 2020 analysis for Gary Works by Barr. That analysis found that the cost of adding low NO_X burners would be $14,100/ton, which is not cost effective. Because of the thermodynamics of heat transfer to the steel in a reheat furnace, a lower flame temperature with low NO_X burners is expected to have negative energy usage impacts, though that impact was not quantified in the BART analysis.

1.2.5.3 EPA's Proposed Emission Limit is Not Feasible

The base case 0.073 lb/MMBtu limit is from a 2019 BACT analysis, and is the lowest possible emission rate that could be identified as RACT. SCR is questionably technically feasible and not cost effective. EPA's assumption of a 40% reduction using add on-control technologies is not supported by any technical analysis for a reheat furnace cited in the CoST modeling. The only citation for a reheat furnace in the CoST references for the proposed rule is to the addition of a low NO_X burner, based on CoST references #283, #289, and #308.

- #283 is the EPA Control Cost Manual that only instructs how to perform economic calculations
- #289 is an analysis performed as part of the NO_X SIP Call that first attempted to assess non-EGU impacts, but did not perform any analyses specific to steel units
- #304 is an EPA document about process heaters overall, focusing on chemical and petroleum refining, with no analysis of steel process heaters

EPA also erroneously found that cost-effective emission reductions are available at a reheat furnace by mis-using the EPA CoST model. The only underlying studies that attempted to calculate steel costs for SCR on a reheat furnace is the 2005 MRPO study, which lumped reheat and annealing furnaces together under a single analysis. The 2005 MRPO study values (in 2005$) for SCR range from $7,566-$13,762/ton for reheat furnaces, with numerous caveats about the generic assumptions and how site-specific variations could result in substantial cost or feasibility differences. When adjusted to 2016$ consistent with the proposed rule via a consumer price index ratio of 1.2, the 2005 MRPO cost range is from $9,079-$16,514/ton. Even without considering the various site-specific caveats in the 2005 MRPO document, and without adjusting the $/ton to reflect ozone-season only operation (with all the capital costs but only 5/12 of a year of operating time and emissions reductions), the absolute minimum cost from the 2005 MRPO report is well beyond the listed maximum cost-effectiveness threshold of $7,500 ton in the proposed rule.

In fact, the upper end of the 2005 MRPO range is very consistent with the SCR cost estimate in the 2014 Irvin RACT study ($16,514/ton vs $18,764/ton), and each is far beyond the maximum cost-effectiveness threshold in the proposed rule.

1.2.6 Annealing Furnace

1.2.6.1 Description

There are two types of annealing furnaces: batch and continuous.

Batch annealing is done in a box-type furnace that consists of a stationary base, several stools on which coils of steel are stacked, individual cylindrical covers for each coil stack (to provide for the protective atmosphere), and the furnace, which is lowered by crane over the base with its load, stools, and cylindrical covers. Subsequently, the charge is heated slowly but uniformly to a specified temperature, soaked for a period of time, and then allowed to cool. After a period of cooling, the furnace is removed to begin a cycle on another base. However, the inner covers are left in place to preserve the protective atmosphere. After the charge has cooled to about 300 °F, the charge can be exposed to air without oxidizing. In this cycle, the cooling period takes at least as long as heating and soaking combined.

Continuous annealing is done in large furnaces in which the steel coil is threaded vertically around rollers located at the top and bottom of the furnace. Thus, the residence time of the steel in the furnace is dramatically increased as it passes continuously through the furnace. A typical, continuous annealing furnace will have several zones including a gas-fired heating zone, a heated holding zone, a heated slow cooling zone, and a fast cooling zone. Steel coil will thread through these zones at a rate of about 1,500 ft/min. Threading back and forth, the steel will make multiple passes through the heating zone in about 20 seconds. Subsequently, it will be cooled to about 1000 °F in the slow cooling zone and then to 240 °F in the fast cooling zone. The entire process takes about 2 minutes and is carried out in an atmosphere of nitrogen (95 percent) and hydrogen (5 percent).

1.2.6.2 Potential for NO_X Reduction

Low NO_X burners are potentially feasible on both continuous and batch annealing furnaces, but the emissions reduction potential and the impacts to operations are unclear.

SCR is technically infeasible on a batch furnace due to the substantial temperature fluctuations in the exhaust gases.

SCR is technically feasible on an annealing furnace, but not cost effective. Most annealing furnaces with SCR have been designed to use SCR originally. Very few annealing furnaces have been retrofitted with SCR, and managing temperatures in the proper range with a retrofit unit is difficult and can require combinations of air tempering, water quenching, and natural gas preheating, depending on several factors including the thickness and width of the steel strip passing through the furnace and also dependent on stage of operations.

Trinity completed a control cost effectiveness analysis on the Irvin open coil annealing furnace, which showed that the SCR cost effectiveness would be at best $28,523 (2021$).

1.2.6.3 EPA's Proposed Emission Limit is Not Feasible

The base case 0.0915 lb/MMBtu limit is from a 2021 BACT analysis, and is the lowest possible emission rate that could be identified as RACT even-though this is BACT, not RACT.

SCR is not technically feasible on a batch annealing furnace, and on a continuous annealing furnace the annual cost effectiveness is at best $28,523/ton.

EPA has erroneously found that cost-effective emission reductions are available at an annealing furnace by mis-using the EPA CoST model. The only underlying studies that attempted to calculate steel costs for SCR on an annealing furnace is the 1994 ACT study and the 2005 MRPO study.

In the 1994 ACT study, EPA noted that there may be problems in installing SCR at existing furnaces, but for new installations estimated annual cost effectiveness up to $11,000/ton for SCR (1994$), and up to $5,000/ton for LNB/SCR (1994$), which would equate in 2022$ to approximately, $22,000/ton and $10,000/ton.

The 2005 MRPO study values (in 2005$) for SCR range from $7,566-$13,762/ton for annealing furnaces, with numerous caveats about the generic assumptions and how site-specific variations could result in substantial cost or feasibility differences. When adjusted to 2016$ consistent with the proposed rule via a consumer price index ratio of 1.2, the 2005 MRPO cost range is from $9,079-$16,514/ton. Even without considering the various site-specific caveats in the 2005 MRPO document, and without adjusting the $/ton to reflect ozone-season only operation (with all the capital costs but only 5/12 of a year of operating time and emissions reductions), the absolute minimum cost from the 2005 MRPO report is well beyond the listed maximum cost-effectiveness threshold of $7,500 ton in the proposed rule.

Regardless of the variations between these estimates, all of the estimates are substantially above the maximum cost effectiveness threshold in the proposed rule of $7,500/ton.

1.2.7 Vacuum Degasser

1.2.7.1 Description

Vacuum degassers (VDGs) are used in the steel industry to remove undesirable gases from molten steel prior to casting to produce the desired properties of the finished steel products. Specific gases to be removed can include hydrogen (H_2), oxygen (O_2), and nitrogen (N_2) dissolved in the liquid metal. They are also used to reduce the carbon content of the steel prior to casting to produce an ultra-low carbon product.

The gases are removed by reducing the pressure above the liquid metal surface to a low value typically 0.5 – 1.0 mmHg (torr). This is accomplished by placing the metal ladle in a degas tank and withdrawing air from the tank using a vacuum pump (liquid ring pump), mechanical vacuum pump, or steam ejectors. The process is typically a batch process lasting about 20 minutes in duration depending on heat size. A hard vacuum is held for about 5 minutes during which argon is injected through the ladle bottom. Stirring the metal with argon allows the dissolved gases to be released at the surface of the metal. The vacuum is then released to close to atmospheric pressure and alloy additions added by chute or on wire feeder. During this process, the metal temperature decreases and reheating can be required in a ladle metallurgical furnace (LMF) before casting.

Gas volume exhausted from the degas tank vary over the degas cycle (e.g., 250 ACFM to 3,000 ACFM) depending on specific product specifications required and degasser equipment design.

Particulate matter (PM) generated by alloy additions are typically removed by a fabric filter or cyclone before entering the vacuum pumps or steam ejectors. Steam ejectors are the most common type of degas vacuum pump used.

During degassing, dissolved oxygen in the liquid metal reacts with carbon and forms CO. If the process is to be operated to prevent carbon reaction, additions are made to the metal to consume oxygen to prevent release of dissolved oxygen to prevent CO formation.

A flare is used to combust the CO. In these systems, air is introduced with natural gas or clean desulfurized coke oven gas to supplement ignition of the flare. The higher heating value (HHV) of the process gases must be higher than 250-300 BTU/SCF to support the operation of the flare.

NO_X is not expected to be formed in the degas tank due to the gas conditions (low oxygen) and non-contact of tank gases with the metal. NO_X however can be formed in the flare flame. NO_X is not directly measured but can be estimated using emission factors.

1.2.7.2 Potential for NO_X Reduction

The application of NO_X control technology is not necessary due to low NO_X emissions nor feasible for the vacuum degasser source category due to the cyclic nature of the process and variable gas flow conditions (i.e., gas volume, temperature, and low NO_X concentrations in process gases).

- NO_X is not generated in the process and NO_X control cannot be applied.
- NO_X is generated by the flare when CO abatement is required and is a function of adiabatic flame temperature which is related to excess air, fuel usage, and flare design.
- NO_X emissions are typically estimated using emission factors derived from petrochemical operations and not directly measured.

1.2.7.3 EPA's Proposed Emission Limit Is Not Feasible

The base case 0.05 lb/MMBtu limit is from two permits (neither of which are included in the docket) and believed to be BACT analyses; BACT analyses represent the lowest possible emission rate that could be identified as RACT.

SCR is not technically feasible due to the NO_X formation occurring at a flare, which is not contained.

EPA's assumption of a 40% reduction using add on-control technologies is not supported by any technical analysis for a vacuum degasser – there is no technical analysis in the docket or in references used as the basis for CoST and MCM for vacuum degassers. In addition, EPA has erroneously found that cost-effective emission reductions are available at vacuum degassers by mis-using the EPA CoST model. See the discussion on blast furnace stove references.

1.2.8 Ladle Metallurgy Furnace

1.2.8.1 Description

Ladle metallurgical furnaces (LMF) are used in the steel industry to increase the liquid metal temperature for casting and to produce steel grades by adding alloys. After production in an electric arc furnace (EAF) or basic oxygen furnace (BOF), the ladle is covered by a water-cooled hood, and three-phase electrodes are inserted through the hood into the liquid. Electric energy is applied to achieve the required metal temperature. Alloys are injected through chutes or through wire feeders to adjust the metal chemistry for the product being produced.

Emissions from the heating and chemical reactions are vented through the area surrounding the electrodes and captured by a hood. The volume of air withdrawn for fume capture is much higher than the volume evolved from the vessel and therefore the gas temperature is low in the exhaust gas. The process is batch typically lasting 20 to 40 minutes. Generation of NO_X emissions is very low since there is no combustion source other than consumption of the electrodes by oxidation with oxygen in capture air.

1.2.8.2 Potential for NO_X Reduction

The gas temperatures and low NO_X concentrations are not consistent with application of selective catalytic reduction (SCR). The gas would require reheating using direct combustion of natural gas for SCR to be feasible.

As noted before, there is no fuel combustion taking place at the LMF, therefore there is no use for low NOx burners.

Trinity completed a control cost effectiveness analysis on the Gary Works LMF, which showed that the SCR cost effectiveness would be at best $1,733,478/ton (2021$). The natural gas combustion required for reheating the exhaust gas would result in an additional 23 tpy of NO_X which is more than the total NO_X

emissions from the LMF, as well as 27,612 tpy of additional CO_2. Additionally, the concentration of NO_X in the gas stream would be very low such that it may be below the minimum level for an SCR to achieve reductions.

1.2.8.3 EPA's Emission Limit is Not Feasible

Low NO_X burners are not technically feasible. EPA's reference to low NO_X burners in the non-EGU TSD represents a misunderstanding of LMF process operations by EPA. In addition, SCR is not cost effective.

EPA's assumption of a 40% reduction using add on-control technologies is not supported by any technical analysis for an LMF – there is no technical analysis in the docket or in references used as the basis for CoST and MCM for LMF. EPA has also erroneously found that cost-effective emission reductions are available at LMF by mis-using the EPA CoST model. See the discussion on blast furnace stove references.

In addition, EPA does not cite a basis for the 0.2 lb/ton reference value and cannot use an un-cited value as the basis for an emission limit. Instead, EPA only generically refers in the non-EGU TSD to

> *EPA considered a range of baseline emission data and current permit limits from 0.20 lb/ton to 0.35 lb/ton.*

Because EPA does not cite a basis for the 0.2 lb/ton emissions level, it is not possible to review the validity of that value, nor the operating conditions under which that value was obtained. Without such documentation, EPA cannot use the 0.2 lb/ton value as the basis for an emissions limit.

1.2.9 Coke Ovens

1.2.9.1 Description

The U. S. Steel Clairton Coke ovens are used to produce metallurgical coke from bituminous coal by indirect heating to remove volatile fractions of the coal. The coal is charged to ovens and heated for 18 to 24, hours, or more depending on coke demand, during which the off-gases are vented to a collection main and transported to a state of the art gas cleaning system, after which particulate matter (PM), ammonia, sulfur, and heavy organics are removed producing a "clean" coke oven gas (COG). The cleaned COG is primarily methane with other hydrocarbons and has a heat value of approximately 500 BTU/SCF.

The coke oven designs employed by U.S. Steel are the byproduct recovery type coke ovens. The byproduct recovery process removes ammonia, light oils, benzene, tars, and H2S limits the potential SO_2 formation during COG combustion and removes nitrogen bearing organics which would increase NO_X formation as fuel NO_X. One distinct difference between by-product recovery coke ovens and non-recovery coke oven is the COG at non-recovery coke ovens is processed to remove particulate but hydrocarbons, H_2S and nitrogen bearing components are not removed.

In a non-byproduct recovery coke oven, combustion of the COG can generate significant concentrations of SO_2 and fuel NO_X; removal of the byproducts in a byproduct recovery coke oven as at U. S. Steel results in far lower SO_2 and fuel NO_X from COG combustion.

After coking the coke is pushed into a hot car and transferred to a quench tower where direct contact with water reduces the coke temperature to prevent combustion with ambient air. The exposure of the hot coke during pushing generates PM emissions which are captured and vented to PM control systems consisting of a fabric filter baghouse. The gases are cooled using dilution air before entering the fabric filter. Since the coke oven heating is a batch process, lasting approximately 2 minutes per push and on average 6-8 pushes an hour, the volume and temperature of the push gases are variable.

Pushing emission controls can include Minister Stein type (i.e., moving hoods), fixed hoods, scrubber cars, or sheds. U.S. Steel operates 10 coke batteries with movable hoods and one shed. Volume of capture gases and gas temperatures are specific to each battery and dependent on oven size.

Minimal fugitive NO_X emissions are generated by combustion of coal particles during coal charging. Coal is charged into the ovens through four charging ports per oven. A Larry Car is used to transport coal from the coal hoppers to each oven. When the Larry Car charges an oven, the lids are removed from the charging ports and drop legs are lowered from the Larry Car to the charging port, covering the charging port. The coal is then systematically fed into an empty oven. This process takes approximately 5 minutes. Any emissions from the charging process are fugitive emissions. NO_X emissions from the process are minimal. There are no gas collection systems suitable for any NO_X controls.

1.2.9.2 Potential for NO_X Reduction

Theoretically SCR could be applied to the pushing control gases after the fabric filter, but the gases would require reheating to the activation temperature using natural gas combustion at significant cost. In addition, the NO_X emissions rate for pushing is expected to be low, decreasing control effectiveness.

Trinity calculated cost effectiveness for potential application of SCR at the Clairton C Battery coke pushing, after the baghouse. The minimum annual cost effectiveness would be $3,121,677/ton (2021$), with 72 tons of NO_X formed from combustion of natural gas to reheat the exhaust gas, as well as approximately 87,000 tpy of added CO_2.

U. S. Steel is not aware of SNCR or SCR being applied to coke oven pushing or charging emissions for coke batteries.

1.2.9.3 EPA's Proposed Emissions Limits are Not Feasible

There are no potential NO_X controls for charging. SCR is a potential NO_X control for pushing, but is not cost effective. EPA's assumption of a 50% or 25% reduction using add on-control technologies is not supported by any technical analysis for coke charging or pushing – there is no technical analysis in the docket or in references used as the basis for CoST and MCM for coke charging or pushing. See the discussion on blast furnace stove references. In addition, EPA has erroneously found that cost-effective emission reductions are available at coke oven charging and pushing by mis-using the EPA CoST model. See the discussion on blast furnace stove references.

Trinity was unable to locate a 0.3 lb/ton coke charging emission factor in AP-42, and EPA does not cite a specific reference. Because EPA's basis for the 0.3 lb/ton emissions level cannot be identified, it is not possible to review the validity of that value, nor the operating conditions under which that value was obtained. Without such documentation, EPA cannot use the 0.3 lb/ton value as the basis for an emissions limit. In addition, EPA must recognize that there are substantial differences between by-products coke oven batteries and non-recovery batteries operations.

Finally, EPA's basis for the 0.02 lb/ton factor is a recent BACT limit, and is the lowest possible emissions rate that can be identified as RACT even though this is a BACT limit and not RACT.

1.2.10 Boilers—Coal, blast furnace gas, coke oven gas

1.2.10.1 Description

Boilers operated at integrated iron and steel facilities and coke oven facilities are multi-fuel fired. Due to the age of the facilities the boilers are from different manufacturers and design (fuels used, heat release rate, and burner configuration, etc.). For these reasons, the expected NOx emission rate will vary from unit to unit burning the same fuel or fuel mixture.

In general, these boilers fire a primary fuel such as BFG or COG gas depending on boiler location, availability of fuel and quantity with natural gas as a flame stability fuel to maintain positive ignition. The boilers due to plant operation are defined as swing load with variable steam demand and therefore variable fuel firing input. Excess air is variable for each fuel type to complete combustion and therefore the flue gas volume will not be constant. The F-factor (which relates heat input to exhaust volume) for each of the fuels is significantly different depending on gas composition. BFG contains a high concentration of inert gases (CO2, N2) and a low HHV (less than 1/10th of NG) which requires a higher combustion air volume, and BFG burns with a low adiabatic flame temperature.

1.2.10.2 Potential for NO_X Reduction

Boilers were previously analyzed for NO_X reductions in multiple studies for U. S. Steel.

- RACT
  - Edgar Thompson (BFG and COG-fired) – AMEC Environmental and Infrastructure, April 1, 2014
  - Irvin (COG-fired) – AMEC Environmental and Infrastructure, April 1, 2014
- BART
  - Clairton – Trinity, March 31, 2022

For the boilers, SCR and SNCR were determined to be technically feasible, but not cost-effective. In the 2022 BART, SCR annual cost effectiveness was at minimum $20,873/ton on Boiler 2, and more expensive on others. The Irvin RACT had similar values, with SCR at ranges of $21,562-$21,778/ton (2014$). Edgar Thompson RACT was somewhat less expensive at $9,285/ton (2014$). All of these values are on an annual basis, and if evaluated for ozone season only, would be appreciably higher. However, even when considered on an annual basis, each of these cost effectiveness values is well above the $7,500/ton threshold EPA used in the proposed rule.

1.2.10.3 EPA' Proposed Emission Limits are Not Feasible

As noted, neither SCR nor low-NOx burners are cost effective options for achieving the emission limits proposed by EPA.

Additionally, the low 0.2 lb/MMBtu emission rate EPA proposes for BFG and COG boilers is well below the emission rates established in recent RACT determinations, which were 0.48 lb/MMBtu (No. 1) and 0.37 lb/MMBtu (No. 2) each on a 30-day rolling average.[11]

[11] Table V-A-1, RACT Installation Permit, ACHD # 0052-I020b, Clairton, April 24, 2020.

1.3 Limit applicability to individual units with PTE > 100 tpy

EPA focused the review for the rule on emission units emitting over 100 tpy.[12] However, EPA is unclear between the preamble and proposed rule regarding just which units the rule are subject to. Additionally, EPA inappropriately includes minor emission units for additional control in the BOF Shops.

In the preamble for steel, EPA states the following regarding applicable units.

> *The EPA is proposing to establish regulatory requirements for the Iron and Steel Mills and Ferroalloy Manufacturing source category that apply to emissions units that directly emit or have the potential to emit 100 tpy or more of NO_X and to facilities containing two or more such units that collectively emit or have the potential to emit 100 tpy or more of NO_X.*
> [87FR20145]

The proposed rule limits aggregation of units to compare against the 100 tpy threshold to the BOF Shop only.

> *The requirements of this section apply to each new or existing emissions unit at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X, and to each BOF Shop containing two or more such units that collectively emit or have the potential to emit 100 tons per year or more of NO_X…*
> [proposed 40CFR52.43(b)]

Based on a phone conversation between Trinity and EPA, EPA's intent in the proposal is represented by the proposal language, where only units within the BOF Shop are aggregated; the EPA suggested that the conflicting language between the preamble and the proposed regulation may have been a carryover from an earlier draft, as EPA staff had been debating just which iron and steel emission units should be aggregated.[13]

EPA should instead limit the regulation only to individual emission units with PTE over 100 tpy, rather than aggregating additional units within the BOF Shop. EPA's definition of BOF Shop follows:

> *BOF Shop means the place where steel making operations occur, beginning with the transfer of molten iron (hot metal) from the torpedo car and ending just prior to casting the molten steel, including hot metal transfer, desulfurization, slag skimming, refining in a basic oxygen process furnace, and ladle metallurgy.*
> [proposed 40CFR52.43(a)]

Based on review of U. S. Steel operations, units that would be included in a BOF Shop are:

- BOF furnace
- Ladle metallurgy furnace (LMF)
- Vacuum degassers
- Ladle preheaters

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[12] 87FR20083

[13] Phone conversation and email between Dylan Mataway-Novak (EPA OAQPS) and Russell Bailey (Trinity), May 23, 2022.

As discussed in Section 6.2 regarding individual units, the LMF, vacuum degassers, and ladle preheaters are small emission units and are operationally distinct from the BOF furnace. These three small emission unit types are often present at facilities outside of the BOF Shop also (such as at EAF facilities), and EPA lists no rationale in the proposed regulation for why these three small emission units should be aggregated with the BOF furnace in determining applicability.

EPA should limit the regulation only to individual emission units with PTE over 100 tpy.

1.4 Development of an emissions control plan requires at least 24 months rather than the 180 days as proposed

The proposed rule requires that affected facilities submit an emissions control plan ("work plan") with 180 days of the effective date of the rule.

> *If you are the owner or operator of an affected unit* [other than a taconite kiln]*, you must submit to EPA a work plan for each affected unit within 180 days of the effective date of this rule identifying how each affected unit will comply with the emissions limits set forth in Table 1 to paragraph (c) of this section. Each work plan must include identification of the control device selected and the phased construction timeframe by which you will design, install, and consistently operate the device.* [proposed 40CFR52.43(d)(A)

Here again as frequently throughout this proposed rule, EPA has modeled requirements for highly variable non-EGUs based on prior experience with EGUs. EPA has proposed a time period that may be appropriate had the required control device actually been installed on numerous facilities, and had those emission units actually demonstrated that the limits can be achieved (such as in the EGU sector). For the steel industry, neither is true, and 180 days is unrealistic and inadequate. Significant engineering assessments would be required in the event EPA moves forward with the proposed rule.

As discussed earlier, the only iron and steel emissions unit where the proposed control technology (SCR) has even been demonstrated has been on annealing furnaces, and even in that category there have been very few installations, and even fewer retrofits. For the remaining emission units, EPA has proposed emission limits based on installation of post-combustion control devices on these units, and there have been zero such installations that have occurred.

EPA should revise this condition to allow a minimum of 24 months to develop an emissions control plan.

1.5 Implementation of the proposed control technologies cannot be completed prior to the 2026 ozone season

As with the emissions control plan requirement, EPA made unrealistic time estimates for installation of control technologies in the steel sector, again significantly based on prior experience with EGUs. In the proposed rule, EPA is proposing that the steel sector units can install post-combustion emissions controls as fast as the EGU sector, which is unrealistic and would be devastating to steel production.

As EPA has noted in numerous prior EGU rules, electricity is fungible – should an individual EGU be offline, in nearly all cases other EGUs can provide sufficient electricity to the electrical grid to offset the loss from a single EGU. Iron and steel production facilities, including boilers at these facilities, are not fungible.

In most cases, should an emissions unit proposed to be regulated under this rule be offline, that entire section of the steel mill would also be offline. Very few steel plants have redundant steel shops, and in most cases when a key production unit is offline, that entire section of the plant is offline.

Assuming parts are available (which is not the current case with the supply chain), installing controls would require a minimum of 36 months IF there were other examples of that control be applied to that type of emissions unit (12 months to design, 18 month design end to installation end, 6 month commissioning), and that is per emissions unit. At a site with some redundancy, for example Gary Works, there are eight boilers potentially subject to this rule, which would lengthen the default 36 month period significantly (all eight boilers are not the same design and all eight boilers cannot be shut down at the same time for installation). And the timing for the installation of this equipment must be viewed against the realities of the worldwide supply chain issues, which only will be compounded by the multiple industries to be regulated in the proposed rule and the overlap in demand design services, equipment and construction services.

Because it is unrealistic and infeasible to install all of the proposed controls prior to the 2026 ozone season, EPA must revise the proposed rule to include a much longer timeframe for compliance. Additionally, because EPA's Step 2 finding that states contribute significantly is based on an analysis of 2026, and because the controls could not be installed by 2026, EPA must re-evaluate whether non-EGU emissions contribute significantly at a later time period (such as 2032 as EPA considered in development of the proposed rule).

1.6 The compliance demonstration method should be stack testing (with an implicit 3-hour average)

As written, the proposed steel rule (4 0CFR 52.43) references both a 3-hour average and a 30-day rolling average as the compliance method. Based on discussion with EPA staff, the intent of the proposed rule was to require a 3-hour averaging period using CEMS.[14]

The compliance demonstration method for the steel emission units should be stack testing, which has an implicit 3-hour average.

Installation costs of CEMs on units could cost up to $1M+ each, along with at least $50,000 in annual compliance costs related to each CEMS' maintenance and QA checks.

1.7 If CEMS are required, the averaging period should be on a 30-day rolling average

EPA has learned that for general emissions units, a 3-hour average is so short as to be unstable in demonstrating compliance. In the boiler world, EPA did issue one NSPS that uses CEMS and has a 3-hour average basis for the limit, which was NSPS Subpart D in 1974. Four years later, in 1978, EPA moved away from a 3-hour average to a 30-day rolling average basis with the new boiler NSPS Subpart D, and six years later in 1984 EPA maintained that 30-day rolling average basis with NSPS Subpart Db. Similarly, the relevant boiler NESHAP (Subparts DDDDD and UUUUU) also use a 30-day rolling average basis when a CEMS is the compliance method.

[14] Phone conversation and email between EPA OAQPS and Trinity, May 23, 2022.

For the same reasons as for boilers, a 3-hour average limit for steel emissions unit using CEMS is inappropriate. For any emissions unit where EPA requires CEMS, the averaging period should be analogous to the NSPS Subpart Da/Db approach, where 30 operating days of data are averaged for comparison to the limit.

1.8 A lb/MMBtu emissions limit is complex for a COG or BFG-fired unit using CEMS

EPA has proposed lb/MMBtu emission limits for multiple steel emission units that fire a range of fuels consisting of natural gas, COG and BFG. To calculate a lb/MMBtu limit, the F-factor of the fuel as fired must be determined (where the F-factor relates the volume of combustion exhaust to the heat input of a certain fuel, all at stoichiometric conditions).

Where an emissions unit fires COG and/or BFG as part of the fuel mix, there is not a constant F-factor. In fact, the F-factor for COG and BFG each varies significantly from the F-factor for natural gas. EPA does provide procedures for developing a custom F-factor that involves obtaining a proximate and ultimate analysis of the fuel as-fired.

It is straightforward to compare against a concentration-based NO_X limit (parts per million by volume, or ppmv), as no F-factor is needed. And it may be feasible to obtain a single F-factor during a 3-hour stack test that could be used to convert to lb/MMBtu for that test. However, it is complex to obtain customized F-factors on an hourly basis to be added to the data acquisition and handling system (DAHS) to convert ppmv to lb/MMBtu.

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APPENDIX A. SUMMARY OF KEY EPA STEEL REFERENCES CITED AS BASIS FOR CoST

- ► EPA 1994e
  - A steel-specific analysis
  - U.S. Environmental Protection Agency, Emissions Standard Division, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document-- NOx Emissions from Iron and Steel Mills," EPA-453/R-94-065, Research Triangle Park, NC, September 1994.

- ► EPA 1998e
  - Less important but often cited by EPA
  - A first attempt by EPA at assessing non-EGUs with respect to ozone
  - Pechan, 1998: E.H. Pechan & Associates, Inc., "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis," prepared for U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Innovative Strategies and Economics Group, Research Triangle Park, September 1998.

- ► Non-EGU TSD Reference 44
  - Cited as an input to EPA2010b
  - Midwest Regional Planning Organization (MRPO). 2005. Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis, prepared by MACTEC

- ► EPA 2010b
  - The most recent steel-specific analysis by EPA
  - EPA, 2010: "NOX CONTROL STRATEGIES IN THE IRON AND STEEL INDUSTRY (11-11-10).pdf", pdf document provided by Donnalee Jones (jones.donnalee@epamail.epa.gov) via email to Amy Vasu 11/16/10.
  - Trinity obtained two related additional file from Ms. Jones as part of our search for references[15]
    - ♦ The 1994 Alternative Control Techniques document mentioned above
    - ♦ NOx Control Technology from Iron and Steel Plants-05-03-10-send.pdf, which appears to be a peer review of the EPA 2010b document.

EPA 1994E

EPA's 1994 Alternative Control Techniques (ACT) document for steel assessed NO_X emission controls on two types of steel emission units included in the proposed rule: reheat furnaces and annealing furnaces, with the following types of control identified on each.

Reheat furnaces
- ► Low excess air (LEA)
- ► Low NO_X burners (LNB)
- ► Flue gas recirculation (FGR)

Annealing furnaces
- ► LNB
- ► FGR
- ► SCR

[15] From an email to Joshua Lee (Trinity) from Donnalee Jones (EPA), May 24, 2022
I think I found it. I also found a couple of other documents that might be useful also, especially the other one from 2010. I have no other documentation than what's in each document.

Reheat furnaces
EPA noted that major modifications to furnace structure and refractories in some existing reheat furnaces. EPA estimated cost effectiveness of emission these technologies at a range of costs up to approximately $1,000/ton (1994$), which is approximately $2,000/ton in 2022$ based on the difference in CPI.

Annealing furnaces
EPA noted that one unit was operational with SCR, and that three were under construction. EPA noted that there may be problems in installing SCR at existing furnaces. While EPA does not discuss continuous versus batch annealing, Trinity believes that the focus of the document was on only continuous annealing units.

EPA estimated cost effectiveness at up to approximately $2,000/ton for LNB/FGR (1994$), up to $11,000/ton for SCR (1994$), and up to $5,000/ton for LNB/SCR (1994$), which would equate in 2022$ to approximately $4,000/ton, $22,000/ton and $10,000/ton.

EPA 1998E

EPA's 1998 ozone non-EGU analysis appears to be the first time that EPA attempted to consider potential non-EGU controls with respect to development of the NO_X SIP Call.

The 1998 non-EGU document, like the EPA1994e, considered reheat and annealing furnaces. Ozone season cost effectiveness was calculated in 1990$.

Reheat furnace - $700-$900 /ton for LNB and/or FGR
Annealing furnace - $1,350-$9,070/ton for mixes of LNB, FGR and SCR

Adjusting to 2022$ would roughly double the $/ton values listed in the report, to $1,400-1,800 and to $2,700-18,140.

It is unclear how much independent research was completed for the steel industry sources. However, the following quotes from the document are germane.

> *It should be noted that although the control technologies selected for use here are generally technically feasible, certain instances are likely to exist where installation of a control is much more problematic, and hence, expensive than the existing cost data suggest. In some instances, site-specific characteristics may result in lower costs, although it is possible that the bias here is low (e.g., costs will be higher than estimated). In some cases it is also possible that the control technology is not technically feasible.*
> [Page 21]

> *Because there are more NO_X emitting source types than there is documented control technique and cost information, some assignments of control efficiency and cost information were made based on like processes being able to be controlled via like control options. This may overstate the NO_X reductions that might be achieved using today's technology.*
> [Page 61]

2005 MRPO BART

MACTEC developed $/ton NO_X estimates for model sources, while noting that site-specific factors can significantly impact the installed costs of pollution control equipment.

Of particular relevance is the lack of consideration of gas stream requirements required by an SCR system.

> *Potential site-specific costs not included but that may be necessary are additional particulate removal equipment and ductwork for a control equipment bypass. If mechanical cleaners are not present, additional gas cleaning may be needed for SCR. Some gas cleaning typically occurs at iron and steel plants. Fuel fired emission units often have bypasses on SCR systems to protect them during startup, shutdown, and malfunction conditions, which could damage the SCR catalyst. As mentioned in the technical feasibility step of the evaluation, if the temperature range is not met by the fuel fired emission unit, modifications would be required to either reduce (for units with temperatures higher than the required catalysts) or increase the boiler gas temperature. Our costs do not include estimates for reheating or providing make up air at lower temperatures to meet the required temperature levels for the SCR to operate. In the case where more heat was required to reach the catalyst temperatures, an actual design would most likely include a duct burner to re-heat the gas stream and a heat exchanger for heat recovery. In this case gas re-heat is required because the exhaust gas is too cool for SCR operating temperature. In addition to a heat exchanger, this option could incur significant costs for duct work and larger air blowers. The potential for fouling the exchanger from dust should also be evaluated. Each facility will have to determine if this option is feasible on a site-specific basis.*
> [Page 32]

The only steel-specific unit for which NO_X costs were estimated by MACTEC is furnaces. While not defined explicitly, when read in context Trinity believes these cost estimates are intended to be applicable to the same furnaces as evaluated in EPA's 1994 ACT report (EPA 1994e).

Costs for furnaces were estimated as follows (presumed 2005$/ton). The range shown is MACTEC's estimate of a low capital cost versus a high capital cost.

Furnaces
- LNB: $2,813-$5,687
- LNB+FGD: $4,205-$9,186
- SCR: $7,566-$13,762
- ULNB[16]+SCR: $8,581-$13,114

When converted to 2022$, the 2005$ are multiplied by approximately 1.5.

MACTEC concluded its model plant assessment by recommending either LNB or ULNB as BART. As noted in the conclusions:

[16] Ultra low NO_X burners

> *In general we proposed ULNB or LNB for NOx control primarily because the costs for these controls are significantly lower than other methods and the marginal improvements in control efficiency are generally not as cost effective.*
> [Page 48]

EPA 2010B

EPA 2010b is the most recent steel-specific document references by MCM or CoST, and Trinity obtained both this document as well as a May 2010 document that appears to be a peer review of an earlier draft of EPA 2010b. EPA 2010b concludes its narrative with the following statement:

> *To capture NOx emissions from this industry, the most likely opportunity is to retrofit low NOx burners into gas fired equipment.*
> [EPA 2010b, Page 1]

An estimated costs page is provided on Page 2 of EPA 2010b, showing SCR costs by CMDB Control Abbreviation, on a 2006$/ton basis.

SCR - $5,970-$7,679
LNB - $2,889
LNB+SCR - $3,964

There is no accompanying analysis to show how these values were derived. However, they are very close to the lowest cost values listed in the 2005 MRPO BART analysis. Trinity believes that the $/ton values are likely derived from the 2005 MRPO BART analysis, and for unknown reasons the creator of EPA 2010b selected the lowest potential cost for each technology.

The source categories for EPA 2010b are unclear and generic consistent with definitions in CMBD and MCM. As such, it is not clear whether EPA intends the EPA 2010b to be limited to the same types of units as EPA1994e or the 2005 MRPO BART analysis.

In the accompanying May 2010 peer review, the $/ton estimates from CoST are compared to the $/ton estimates from the 2005 MRPO BART analysis and EPA 1994e (1994 ACT). The $/ton values from CoST are appreciably lower than the other two reference sources. There is no discussion of the difference between CoST and the other two references, but there is a quote between the CoST data table and the other reference tables that appears to reference the cost difference.

> *The costs for Iron and Steel are expected to be highly site-specific and variable depending on the size of the combustion or process unit. Consequently, it is uninformative to present a single cost effectiveness number unless it incorporates a scaling factor.*

APPENDIX B. SELECTED EPA CoST REFERENCES NOT INCLUDED IN DOCKET

MCM Reference EPA2010b and related files

Non-EGU TSD Reference #44

The 1994 EPA Iron and Steel ACT document is included in
the docket and not provided with these comments.
EPA-HQ-OAR-2021-0668-0038
(MCM EPA 1994e, CoST Reference 308, and
Non-EGU TSD citations 34, 36, 43, 49, 50)

The 1998 Pechan document is in a prior rulemaking docket
EPA-HQ-OAR-2001-0008-0321
and not provided with these comments
(MCM EPA 1998e, CoST Reference 289)

APPENDIX C. EPA MENU OF CONTROL MEASURES FOR STEEL SOURCE CATEGORY

Russell Bailey

From: Joshua Lee
Sent: Wednesday, May 25, 2022 11:07 AM
To: Russell Bailey
Subject: FW: EPA 2010b
Attachments: noxcontrolreview-11-11-10-send.pdf; NOx Control Technology from Iron and Steel Plants-05-03-10-send.pdf; NOX-ACT-steel-1994.pdf

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From: Jones, DonnaLee <Jones.Donnalee@epa.gov>
Sent: Tuesday, May 24, 2022 11:25 AM
To: Joshua Lee <Joshua.Lee@trinityconsultants.com>
Subject: RE: EPA 2010b

I think I found it. I also found a couple of other documents that might be useful also, especially the other one from 2010.

I have no other documentation than what's in each document.

Regards,
Donna Lee Jones, Ph.D.
Senior Technical Advisor, Metals Sector
U. S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Sector Policies and Programs Division / Metals & Inorganic Chemicals Group (D243-02)
Research Triangle Park, NC 27711 Tele: (919) 541-5251 Fax (919) 541-3207
~~~~~~
"Reasonableness never fails to be appreciated." - anon.

Pronouns - She/Her/Hers
Salutation - Dr./Ms.

From: Joshua Lee <Joshua.Lee@trinityconsultants.com>
Sent: Tuesday, May 24, 2022 11:43 AM
To: Jones, DonnaLee <Jones.Donnalee@epa.gov>
Subject: EPA 2010b

Hello Dr. Donnalee Jones,

The following is the information I was talking about on the phone regarding the document I am looking for:

- EPA, 2010: "NOX CONTROL STRATEGIES IN THE IRON AND STEEL INDUSTRY (11-11-10).pdf", pdf document provided by Donnalee Jones (jones.donnalee@epamail.epa.gov) via email to Amy Vasu 11/16/10.

This is found on the EPA menu of control measures excel sheet with the key "EPA 2010b" in the references tab. The link to the sheet from online is attached below.
~~~~~~

https://www.epa.gov/sites/default/files/2016-02/menuofcontrolmeasures.xlsx

If you could please send me this document when you get the chance that would be great. Thanks,

Joshua Lee
Intern

P 636.256.7200
Email: Joshua.lee@trinityconsultants.com

Trinity Consultants

Control Technology for NO_x Emissions from Iron and Steel Plants

- **Have we properly characterized available NO_x controls?**
  - Low NO_x Burners (LNB)
  - LNB with Flue Gas Recirculation (FGR)
  - LNB with Selective Non-Catalytic Reduction (SNCR)
  - Ultra-Low NO_x Burners (ULNB)
  - ULNB with Selective Catalytic Reduction (SCR)
  - SCR

Response: Yes, for the most part (descriptions of these technologies are included in Appendix A). These technologies are applicable to the various types of reheat, annealing, and other gas-fired furnaces used at steel plants, as well as boilers. A review of Title V permits indicates that the most common NO_x controls used are low-NOx burners (LNB). Few of the other technologies are currently applied.

*Aside from the heating furnaces and boilers, which are primarily combustion units, other sources of NO_x include coke plant underfiring stacks, sinter plants, blast furnaces, and steelmaking furnaces. (A discussion of NO_x control for electric arc furnace (EAF) steelmaking is given in Appendix A.) Based on our study of two steel mills and a coke plant in the Detroit area (*Reference 1 *below), we concluded the following:*

"The BART analysis concluded that low-NO_x burners and ultra-low NO_x burners represented BART for iron and steel sources. As shown in Table 6-2, these controls are cost-effective. Our survey of the three plants indicated that NO_x controls were not widely implemented. The EES Coke battery's underfiring system is equipped with staged heating and flue gas recirculation to reduce NO_x emissions. U.S Steel's continuous galvanizing line is equipped with selective catalytic reduction to reduce NO_x emissions. In addition, Severstal plans to install low-NO_x burners on their blast furnace stoves."

The table below from the Detroit study shows the major contributors to NO_x emissions at integrated iron and steel plants. The reheat and other furnaces are a primary contributor, along with boilers, blast furnace (BF) stoves, basic oxygen furnaces (BOFs) used to make steel, and the coke oven combustion (or underfiring) stack.

No emissions are shown in the table for sinter plants because the Detroit steel mills do not have a sinter plant. However, there are currently five sinter plants at integrated mills, and we know that sinter plants are significant NO_x emitters.

NO_x Emission Sources (Ranked) at Iron and Steel Plants in Detroit Area (Reference 1)

Source	NO_x Emissions (tpy)	Plant
Mill furnace heaters	629	US Steel
No. 2 Boilerhouse	493	US Steel
D blast furnace stove	387	US Steel
B blast furnace stove	342	US Steel
C BF stoves	337	Severstal
Combustion stack	337	EES coke plant
Reheat furnace 1	331	Severstal
Reheat furnace 2	331	Severstal
Reheat furnace 3	331	Severstal
Blast furnace flares	330	US Steel
No. 1 Boilerhouse	322	US Steel
B BF stoves	218	Severstal
BOF	191	Severstal
Coke oven gas flares	136	Coke plant
BOF ESP stack	130	US Steel
Annealing furnace (NG)	130	Severstal
Heaters (NG)	83	US Steel
Dryout heaters (NG)	81	US Steel
Heaters (NG)	60	US Steel
No. 1 Boiler	58	US Steel
Process heaters (NG)	55	US Steel
Boiler	38	US Steel
Tapping BOF	33	US Steel
Annealing heaters (NG)	32	US Steel
BOF tapping	29	Severstal
C BF casthouse	24	Severstal
B BF casthouse	21	US Steel
D BF casthouse	20	US Steel
Annealing heaters (NG)	17	US Steel
BOF operation (NG)	17	US Steel
Heaters (NG)	15	US Steel
No. 3 Boilerhouse (NG)	15	US Steel
B BF casthouse	14	Severstal
Heaters (NG)	11	US Steel

- **What are the available documents for information on NO_x controls**
  [*Note: The first three below also have cost and cost effectiveness estimates]*

  1. Branscome, M., and S. Burns. 2006. Evaluation of $PM_{2.5}$ Emissions and Controls at Two Michigan Steel Mills and a Coke Oven Battery. Prepared for the Air Quality Strategies and Standards Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC. Available at http://epa.gov/air/caaac/aqm/detroit_steel_report_final_20060207.pdf

  2. Midwest Regional Planning Organization (RPO). *Boiler Best Available Retrofit Technology (BART) Engineering Analysis.* Prepared for The Lake Michigan Air Directors Consortium (LADCO). March 30, 2005. Available at http://www.ladco.org/reports/control/bart/iron_and_steel_mills.pdf.

  3. Alternative Control Techniques Document (ACT) – NO_x Emissions from Iron and Steel Mills. EPA September 1994. Available at http://www.epa.gov/ttn/catc/dir1/iron_act.pdf.

  4. "Proper Application of Low-NOx Technology to Reheating Furnaces – Environmental and Efficiency Advantages." (April 2005). David G. Schalles and John C. Dormire, Bloom Engineering Col Inc., Pittsburgh, PA. Published in AIST's "Iron and Steel Technology."

  5. "Fuel Savings and Reduced Emissions: Experience from 80 Oxy-fuel Installations in Reheat Furnaces." (May 2005). Per Verterberg, J. von Scheele, G. Moroz. Published in AIST's "Iron and Steel Technology."

- **How do NO_x control costs differ for subparts of the industry**

We have no information on how costs differ for different subparts. However, we expect that the size of the combustion unit is a primary factor affecting cost or cost effectiveness.

- **What Iron and Steel Sector project work is underway that may inform development of NO_x cost curves**

  None at this time.

- **What is the general assessment of workload needed to develop defensible and reliable cost**

  A. Heating furnaces and boilers at Iron and Steel plants – **hours estimated: 8 hours**

  The NO_x controls used for heating furnaces and boilers at iron and steel plants should be the same as those developed for other sources and sectors. Consequently, the research done on other sectors could be applied here. We could develop information on the size distributions of these combustion units for iron and steel plants if that would help to inform the cost analysis.

B. Other NOx Sources - **hours estimated: 40 hours**

- **Degree to which sources in industry likely to have NO_x CEMs**

  We reviewed several title V permits, and a few of the largest plants have CEMS on a few of their larger units. Most do not have CEMS, so we believe CEMS are not very widespread.

- **Reasonableness of the cost effectiveness estimates as compared to EPA estimates**

CoST Analysis Results for 2012*

Iron and Steel**	30300933 steel reheat furnaces	LNB + FGR	$600/ton
	30390004 fuel fired eq: process gas	LNB + FGR	$900/ton
	30390003 fuel fired eq: natl gas	ULNB	$2,400/ton
	30300306 coke oven underfire stack	SNCR	$2,600/ton
	30300934 steel heat treating/annealing	LNB + SNCR	$2,700/ton

* Based on the 2012 EPA inventory and NOx controls less than $5,000/ton (GSG/AQPD).
** 1.5% of overall nonEGU NOx reduction estimates.

The costs for Iron and Steel are expected to be highly site-specific and variable depending on the size of the combustion or process unit. Consequently, it is uninformative to present a single cost effectiveness number unless it incorporates a scaling factor. Estimates are given below from the BART analysis (Reference 2) and from the ACT document (Reference 3).

Summary of Cost Estimates for NO_x Controls for Furnaces at Iron and Steel Plants from the BART analysis (Reference 2) in $2004

Control Technology	Removal Efficiency %	Low Cost Effectiveness ($/ton NOx removed)	High Cost Effectiveness ($/ton NOx removed)
Low-NOx burners (LNB)	40	$2,813	$5,867
Low-NOx burners plus flue gas recirculation (LNB+FGR)	50	$6,055	$9,186
	72	$4,205	$6,379
Low-NOx burners plus selective non-catalytic reduction (LNB+SNCR)	50	$6,704	$10,493
	89	$3,766	$5,895
Ultra-low NOx burners (ULNB)	75	--	$2,018
	85	--	$1,781
Ultra-low NOx burners plus selective catalytic reduction (ULNB+SCR)	85	$9,792	$13,114
	97	$8,581	$11,492
Selective catalytic reduction (SCR)	70	$9,728	$13,762
	90	$7,566	$10,704

Summary of Costs Estimates for Controls for Furnaces at Iron and Steel Plants from EPA's ACT (Reference 3) in $2008

Type of Furnace	Control Technology	Low Cost Effectiveness ($/ton)	High Cost Effectiveness ($/ton)
Reheat Furnaces	Low Excess Air	$641	$3,752
	Low NOx Burner (LNB)	$141	$625
	Low NOx Burner plus Flue Gas Recirculation (LNB+FGR)	$172	$1,079
Annealing Furnaces	Low NOx Burner (LMB)	$313	$2,032
	Low NOx Burner plus Flue Gas Recirculation (LNB+FGR)	$406	$2,501
	Selective Non-Catalytic Reduction (SNCR)	$907	$5,784
	Selective Catalytic Reduction (SCR)	$1,876	$11,255
	Low NOx Burner plus Selective Catalytic Reduction (LNB+SCR)	$2,032	$12,349
	Low NOx Burner plus Selective Non-Catalytic Reduction (LNB+SNCR)	$891	$5,315
Galvanizing Furnaces	Low NOx Burner (LNB)	$172	$1,407
	Low NOx Burner plus flue gas recirculation (LNB+FGR)	$219	$1,876

Appendix A. Summary of NO_x Controls for Electric Arc Furnaces (EAFs)

Nitrogen oxide emissions from EAF can be electric NOx, thermal NOx, or fuel NOx. The following discusses the formation of the NOx and potential controls as taken from the steel industry's "The Making, Shaping, and Treating of Steel."

Electric NOx

Electrical NOx is formed in furnace operations when nitrogen passes through the arc between electrodes. This "electrical" NOx can be reduced by reducing the amount of nitrogen available in the furnace. This can be achieved by closing up furnace gaps and by closing the slag door whenever possible. Many operations lance oxygen through the door and, as a result, a large volume of air enters the furnace. This can be reduced by providing a shield close to the door or by hanging chains close to the opening. Foamy slag practice can be beneficial since the slag foams up partially blocking the opening. Also, since foamy slag helps to bury the arc, it is more difficult for nitrogen to pass through the arc and be ionized.

Thermal NOx

Thermal NOx is generated from burner use in EAFs. Typical levels of NO_x reported are in the range of 36–90 g NO_x per ton of steel. Thermal NOx can be addressed using any of the conventional control methods. Typically, thermal NO_x is reduced by improving the burner design and providing good mixing of the pre-combustion gases. Thermal NO_x is also formed in the water-cooled duct following the combustion air gap as any combustible materials burn with the oxygen which has entered the ductwork in the combustion air. If all of the combustible material burns quickly, the gas temperature will reach a level where thermal NO_x is formed. One option which is now being investigated is to close up the combustion gap somewhat and to supply combustion air at various points in the water-cooled duct downstream of the combustion gap through injectors. Thus the combustion will be staged along the first two-thirds of the water-cooled duct and will avoid the temperatures associated with thermal NO_x generation.

Fuel NOx

As with most fuel-fired NO_x sources, there are two broad categories of NO_x reduction techniques: (1) process controls, including combustion modifications, that rely on reducing or inhibiting the formation of NO_x in the production process and (2) post-combustion (secondary) add-on controls, where flue gases are treated to remove NO_x that has already been formed.

For iron and steel plants, six different control technologies or control technology combinations were identified for NO_x emissions from fuel-fired emission units at iron and steel plants. These technologies, which provide both combustion or post-combustion controls (or a combination of both), are described below.

Flue gas recirculation (FGR) uses flue gas as an inert material to reduce flame temperatures. In a typical FGR system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The flue gas is mixed with the combustion air and introduced into the burner. The addition of flue gas reduces the oxygen content of the combustion air, which in turn reduces flame temperatures, resulting in lower NO_x emissions.

Typical NO_x control efficiency for FGR ranges from 30 percent to 50 percent, or 50 to 72 percent when coupled with low-NO_x burners.

Low-NOx burner (LNB) technology uses advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. LNB is a staged combustion process that is designed to split fuel combustion into two zones: primary combustion and secondary combustion.

Two general types of LNBs exist: staged fuel and staged air. Staged-fuel LNBs separate the combustion zone into two regions. In the first region, combustion takes place in the presence of a large excess of oxygen at substantially lower temperatures than a standard burner. In the second region, the remaining fuel is injected and combusted with any oxygen left over from the primary region. The remaining fuel is introduced in the second stage outside of the primary combustion zone so that the fuel and oxygen are mixed diffusively (rather than turbulently) which maximizes the reducing conditions. LNBs inhibit the formation of thermal NO_x, but have little effect on fuel NO_x. Therefore, staged-fuel LNBs are particularly well suited for coal- and natural gas-fired emissions units that are higher in thermal NO_x. The estimated NO_x control efficiency for LNBs in high-temperature applications is 25 percent. However, when coupled with FGR or selective non-catalytic reduction (SNCR), these efficiencies increase to 50 to 72 and 50 to 89 percent, respectively.

Ultra low-NO_x burners (ULNB) combine the benefits of flue gas recirculation and low-NO_x burner control technologies. Rather than a system of fans and blowers (like FGR), the burner itself is designed to recirculate hot flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below that necessary for optimal combustion efficiency. Because of this reduction in temperature, ULNB would likely only be applicable to processes at iron and steel plants that are not temperature dependent, unless the reduction in flame temperature does not fall below the required threshold temperature for the process. The estimated NO_x control efficiency for ULNBs in high-temperature applications is 50 percent. Newer designs have yielded efficiencies between 75 to 85 percent. When coupled with selective catalytic reduction, efficiencies from 85 to 97 percent can be obtained.

Selective non-catalytic reduction (SNCR) is a control process that injects urea or ammonia-based chemicals into the flue gas stream to convert NO to N2 and water. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The reaction with urea is as follows:

$$2NO + CO(NH_2)_2 + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2\ H_2O$$

The optimum operating temperature for SNCR is 1,600°F to 2,100°F. Under these temperature conditions, a significant reduction in NO_x occurs. At temperatures above 2,000°F, an alternative reaction occurs and NO_x control efficiency decreases rapidly. The normal NO_x control efficiency range for SNCR is 50 to 70 percent. To date, there are no known installations of SNCR at iron and steel plants, although SNCR potentially could be used for some operations within an iron and steel plant.

Selective catalytic reduction (SCR) is a post-combustion NOx control technology in which ammonia (NH3) is injected into the post-combustion gas stream in the presence of a catalyst. A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NOx decomposition. NOx is removed through the following chemical reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

The reaction of NH_3 and NOx is favored by the presence of excess oxygen. However, the primary variable affecting NOx reduction is temperature. Optimum NOx reduction occurs at catalyst bed temperatures of 600–750°F for conventional catalysts (vanadium or titanium based) and 470–510°F for platinum catalysts. A high temperature zeolite catalyst is also available; it can operate in the 600–1000°F temperature range.

A given catalyst typically provides optimal performance within ± 50°F of its design temperature for applications in which flue gas oxygen concentrations are greater than 1 percent. Below this optimum range, the catalyst activity is greatly reduced allowing unreacted NH_3 to slip through (ammonia slip). At temperatures above 850°F, ammonia begins to oxidize to form additional NOx. The NH_3 oxidation to NOx increases with increasing temperature. The normal NOx control efficiency range for SCR is 70 percent to 90 percent. SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the United States. There have been few uses of SCR in the iron and steel industry. At the time the EPA's ACT NOx document was published, Japanese iron and steel mills had been experimenting with SCR for sinter plants and coke ovens, however these efforts at that time were experimental.

As indicated above, SCR has been used with annealing furnaces. There are few other references to the use of SCR for NOx control for other emission processes at iron and steel plants. MACTEC did find one example usage of SCR for controlling sintering plant exhaust gases. Of particular interest in that example installation was the use of iron ore as the catalyst. The benefit of using iron ore as the catalyst was that unlike other types of catalyst which have a solid waste disposal component, the iron ore can be used directly as a steel making raw material, thus obviating the solid waste disposal issue. In the SCR process, typically, anhydrous ammonia usually diluted with air or steam is injected into hot flue gases, which then pass through a catalyst bed where NOx is reduced to nitrogen gas and water. As indicated above, the optimum temperature for SCR depends on the catalyst. Thus the exit gas temperatures from some of the processes at iron and steel plants may either be too high or too low, requiring either reheat (if too low) or dilution/quenching (if too high) in order to effectively use SCR. Thus careful consideration should be given on a source-specific basis depending on how raw materials are currently processed.

Burner Technology Options for NOx control include the following:

- Nonsymmetrical air-staged burner for longitudinal or side-fired zones
- Air-staged burner for roof firing
- Air-staged long flame burners for low-pressure fuels
- Ultralow-NOx regenerative burners

NO_X CONTROL STRATEGIES IN THE IRON AND STEEL INDUSTRY (11-11-10)

We reviewed the table of strategies for NOx control in the iron and steel industry and identified CMDB processes: NSNCRCMOU, NDSCRFPGCO, NDSCRUPGCO, NDSCRUNGGN, NLNBUNGGN and NLNBUPGCO, NDSCRUROGN, NDSCRBCGN, NSNCRBCGN, and NLNBFCOBF, as possibilities for use in the iron and steel industry. See attached table.

Our present focus for regulatory review in the integrated iron and steel segment is sinter plants, blast furnaces and basic oxygen process furnaces. The Alternative Control Techniques Document --NO_x Emissions from Iron and Steel Mills, September, 1994 (EPA-453/R-94-065) is 16 years old, but there has not been much new construction in the industry. At the time this study was done, EPA had no recommendations for the processes that we are currently targeting but suggested low NO_x burners and *possibly* SCR for some gas fired equipment at iron and steel plants such as annealing furnaces, preheating furnaces and boilers. (NO_x control options for boilers at iron and steel facilities are about the same as those for boilers anywhere.)

A BART (Best available retrofit technology) study was done in 2005 by MACTEC [Midwest Regional Planning Organization (RPO): Iron and Steel Mills Best Available Retrofit Technology (BART) Engineering Analysis, MACTEC, March 30, 2005. This study looked at two steel mills in the Midwest and found that no low NO_x technologies were in place at these plants. For processes on which we are focusing, the recommended retrofits technologies of ultralow NO_x burners (ULNB) for the sinter plant windbox and low NO_x burners (LNB) or ULNB for coke oven underfire. For other emission points (general gas fired equipment) they recommended retrofit technologies of LNB or ULNB for boilers, slab furnaces, annealing furnaces, hot strip mill furnaces, heat soaking, etc. They also recommended ULNB for the refining cycle (but not for charging, tapping, or slagging) of the basic oxygen furnace.

Bearing in mind that there are many different combustion processes at a steel plant, some NO_x reductions may be achieved at some points in the process. NSNCRCMOU and NSNCRBCGN are selective non-catalytic reduction processes which were considered infeasible in the BART study. NDSCRUROGN and NDSCRBCGN are unlikely because little if any residual fuel oil is combusted (it is possible but unlikely) and little if any bituminous coal is combusted (a fraction of the coke is sometimes replaces with coal, because it is cheaper, but not very much). NDSCRFPGCO, NDSCRUPGCO and NDSCRUNGGN are SCR processes which the Bart study considered feasible (for some emission points). NLNBUNGGN/NLNBUPGCO, and NLNBFCOBF are low NO_x burner processes which were considered feasible in the Bart study (for some emission points).

To capture NO_x emissions from this industry, the most likely opportunity is to retrofit low NO_x burners into gas fired equipment. Also, for boilers at steel plants as with boilers everywhere, other types of “combustion modifications” may be possible.

Control Options for Reducing Nitrogen Oxides Emissions from Point and Area Sources

Iron and Steel?	CMDB Control Abbreviation	Emission Reduction Measure Name (Note)	Source Category	Control Efficiency (%)	Cost Effectiveness (2006$/ton reduced)	References	Description/Notes/Caveats
Yes	NDSCRFPGCO	Selective Catalytic Reduction--(Bart study considered SCR feasible)	In-Process - Process Gas - Coke Oven Gas	90	$7,679	167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to process gas fired ICI boilers with NOx emissions greater than 10 tons per year.
Yes	NDSCRUPGCO	Selective Catalytic Reduction-(About same as NDSCRFPGCO)	In-Process - Process Gas - Coke Oven Gas	90	$5,970	167	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process process gas usage from Coke Oven Gas.
Yes	NDSCRUNGGN	Selective Catalytic Reduction-(Very similar to NDSCRFPGCO)	In-Process Fuel Use - Natural Gas	90	$5,970	167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process natural gas usage and uncontrolled NOx emissions greater than 10 tons per year.
Yes	NLNBUNGGN and NLNBUPGCO	Low NOx Burner--(Bart study considered this feasible)	In-Process Fuel Use - Natural Gas or Coke Oven Process Gas	50	$3,531 for NOx<1 tpd and $2,889 for NOx>1 tpd	72, 175, 179, 186	This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to operations with in-process coke oven gas usage and natural gas-fired process heaters with uncontrolled NOx emissions greater than 10 tons per year.
Yes	NLNBFCOBF	Low NOx Burner and Flue Gas Recirculation--(Bart study considered this feasible)	In-Process -Process Gas -Coke Oven/ Blast Furnace	55	$5,120 for NOx<1 tpd and $3,964 for NOx>1 tpd	72, 172, 175, 179, 186	This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to in-process coke/blast furnaces and uncontrolled NOx emissions greater than 10 tons per year.
Maybe	NDSCRUROGN	Selective Catalytic Reduction-(Use of residual fuel oil is not usually practiced in Iron and Steel, but could be used for a boiler or process heater on site)	In-Process Fuel Use - Residual Oil	90	$5,374	167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process residual oil usage and uncontrolled NOx emissions greater than 10 tons per year.
Maybe	NDSCRBCGN	Selective Catalytic Reduction--(Not likely in Iron and Steel except where some coke is replaced with coal due to lower cost)	In-Process Fuel Use - Bituminous Coal	90	$3,649	167	This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control applies to operations with general (in process) bituminous coal use and uncontrolled NOx emissions greater than 10 tons per year.
No	NSNCRCMOU	Selective Non-Catalytic Reduction--(Bart study considered SNCR infeasible)	By-Product Coke Manufacturing - Oven Underfiring	60	$2,632	72, 172, 175, 179, 181	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to all by-product coke manufacturing operations with oven underfiring and uncontrolled NOx emissions greater than 10 tons per year.
No	NSNCRBCGN	Selective Non-Catalytic Reduction--(Bart study considered SNCR infeasible)	In-Process Fuel Use - Bituminous Coal - Gen	40	$2,022 for NOx<1 tpd and $1,509 for NOx>1 tpd	72, 172, 175, 179, 185	This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to operations with general (in process) bituminous coal use and uncontrolled NOx emissions greater than 10 tons per year.

Midwest Regional Planning Organization (RPO)

Iron and Steel Mills Best Available Retrofit Technology (BART)

Engineering Analysis

Prepared for:

The Lake Michigan Air Directors Consortium

(LADCO)

Prepared by:

MACTEC Federal Programs / MACTEC Engineering and Consulting, Inc.

(MACTEC)

March 30, 2005

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SECTION 1
OVERVIEW

INTRODUCTION

An appropriate first step in evaluating BART for a group of sources is to categorize emission units within each general source category. For this work, the source categories included (BART numeric category in parentheses):

- Portland cement plants (4),
- Iron and steel mill plants (6),
- Primary aluminum ore reduction plants (7),
- Petroleum refineries (11),
- Primary lead smelters (17),
- Chemical process plants (21), and
- Fossil-fuel boilers of more than 250 million BTUs per hour heat input (22)

In general, these types of emission units were found in several of the LADCO States. In order to effectively characterize the BART controls for these emission sources, MACTEC determined that using an initial “model” emission source for each category would be the most effective means of evaluating the types of emission units and the likely candidate BART controls for each.

For each of these emission sources, MACTEC developed “model sources” to enable the development of representative control cost estimates. The physical characteristics of the model sources are summarized in each section specific to that source category. The model sources were selected to reflect typical emission units found at each emission source type.

SECTION 2
AVAILABLE CONTROL TECHNOLOGIES

INTRODUCTION

This section describes each potentially available control technology evaluated for BART category 6, iron and steel plants. For iron and steel plants, the control technologies can be largely focused by pollutant and emission unit type within the facility. Table 2.1 shows the types of emission sources (summarized by SCC) that were found to be potentially subject to BART for iron and steel plants. From this table it can clearly be seen that the majority of emissions of SO_2 and NO_x are generally associated with fuel firing operations, in this case either boilers or process heaters. There are also emissions of SO_2 from SCC 30300699. The SCC description indicates that emissions are from unclassified open furnace activities. In this case, these emissions are from sinter heating/processing, which is also likely to be fuel based. For NO_x there are also emissions from hot metal transfer. The hot metal transfer emission unit description refers to basic oxygen furnace refining cycle processes. As a consequence, our discussion of BART for iron and steel plants will focus on fuel combustion controls for the SO_2 and NO_x sources, since this will account for controls on 100 percent of the SO_2 and over 96 percent of the NO_x. Fuel firing sources also account for 45 percent of the PM and 68 percent of the VOC emissions. For the remaining sources (which are primarily PM and VOC emitters) the BART analysis will focus only on controls for those pollutants.

For fuel firing equipment, the control devices will be very similar to those identified for boilers (BART category 22). SO_2 controls evaluated include advanced flue gas desulfurization (AFGD), wet FGD and dry FGD. NO_x, controls evaluated include low NO_x burners (LNB), flue gas recirculation (FGR), selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). PM controls include fabric filters (both typical baghouse setups and baghouses with traveling hoods), dust cartridges (DC), and wet and dry electrostatic precipitators (ESP). In addition, for PM only sources (especially fugitive ones), best management practices need to be examined to determine if they are sufficient for BART. For this section, the technologies are grouped by the pollutant that they control for fuel fired sources (i.e., NO_x, SO_2, PM, or VOC). That is followed by a section discussing the technologies available for PM only sources.

Determining technical feasibility of a control technology for a new source (e.g., determining best available control technology for a new process heater source at an iron and steel plant) is different than determining technical feasibility for a retrofit at an existing source (e.g., determining best available retrofit technology for an existing process heater at an iron and steel plant). In this section, MACTEC determines the technical feasibility of each of at least three control technologies (if available) for fuel fired and PM only units at a typical iron and steel plant. As part of the BART screening evaluation, a literature/internet/vendor review was conducted to identify potential control equipment options for the emission units identified (see below). The controls identified represent the top three options (based on control efficiency and costs) for these units. The top controls were identified in a spreadsheet provided to LADCO in December 2004 and updated in January 2005 to address comments received on the December spreadsheet.

In the section that follows, MACTEC further evaluates the technical feasibility of each control technology as a retrofit to the existing emission units identified in task 2 of this contract (and provided in a spreadsheet to LADCO participants in October 2004). The emission units identified in that spreadsheet were selected based on three criteria: 1) emission levels for SO_2 and NO_x; 2) commonality of sources (i.e., how many similar sources occurred across the LADCO region and; 3) the potential impact of emissions from these units at Class I areas (as determined by Q/D [emissions/distance] values for several Class I areas in or near the LADCO region). In addition, cost estimates have been modified to the extent possible to reflect actual emission unit operational conditions.

Table 2.2 shows the iron and steel plant emission units identified for LADCO as meeting the three criteria listed above. These emission units were evaluated for BART.

TABLE 2.1 LADCO BART CATEGORY 6 (IRON AND STEEL PLANT) SCC-BASED SOURCE TYPES AND EMISSIONS

SCC	SCC DESCRIPTION	SO_2	NO_2	PM	VOC
10200707	External Combustion Boilers Industrial Process Gas Coke Oven Gas	2111.01	700.23	71.91	2.06
30300302	Industrial Processes Primary Metal Production By-product Coke Manufacturing Oven Charging	0	23.25	105.16	11.58
30300304	Industrial Processes Primary Metal Production By-product Coke Manufacturing Quenching	0	0	1.39	2.29
30300699	Industrial Processes Primary Metal Production Ferroalloy, Open Furnace Other Not Classified	1733.82	1274.19	187.41	307.82
30300825	Industrial Processes Primary Metal Production Iron Production (See 3-03-015 for Integrated Iron & Steel MACT) Cast House	0	80.49	84.13	0
30300913	Industrial Processes Primary Metal Production Steel Manufacturing (See 3-03-015 for Integrated Iron & Steel MACT) Basic Oxygen Furnace: Open Hood-Stack		53.8	203.04	8.3
30300915	Industrial Processes Primary Metal Production Steel Manufacturing (See 3-03-015 for Integrated Iron & Steel MACT) Hot Metal (Iron) Transfer to Steelmaking Furnace	0	188.94	48.81	18.2
30300931	Industrial Processes Primary Metal Production Steel Manufacturing (See 3-03-015 for Integrated Iron & Steel MACT) Hot Rolling	0	0	211.67	273
30300932	Industrial Processes Primary Metal Production Steel Manufacturing (See 3-03-015 for Integrated Iron & Steel MACT) Scarfing	0	0	10.97	0
30301502	Industrial Processes Primary Metal Production Integrated Iron and Steel Manufacturing (See also 3-03-008 & 3-03-009) Sintering: Raw Materials Handling	0	0	0.42	0
30301504	Industrial Processes Primary Metal Production Integrated Iron and Steel Manufacturing (See also 3-03-008 & 3-03-009) Sintering: Discharge End	0	0	127.17	0
30390002	Industrial Processes Primary Metal Production Fuel Fired Equipment Residual Oil: Process Heaters	0	0	0	0
30390003	Industrial Processes Primary Metal Production Fuel Fired Equipment Natural Gas: Process Heaters	3.64	2132.83	29.73	12.32
30390004	Industrial Processes Primary Metal Production Fuel Fired Equipment Process Gas: Process Heaters	9978.28	5430.42	361.4	346.79
39000689	Industrial Processes In-process Fuel Use Natural Gas General	323.1	334.37	13.89	1.1

TABLE 2.2 LADCO BART CATEGORY 6 (IRON AND STEEL PLANTS) EMISSION UNITS

STATE	SOURCE NAME	SOURCE ID	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO_2	NO_2	PM	VOC
ILLINOIS	National Steel Corp	119813AAI	0015	SLAB FURNACE #1	0.34	227.31	2.89	0.79
ILLINOIS	National Steel Corp	119813AAI	0033	BOF - TWO VESSELS		53.8	203.04	8.3
ILLINOIS	National Steel Corp	119813AAI	0041	BOILER HOUSE 1: BOILERS 1 TO 7	830.53	275.49	28.29	0.81
ILLINOIS	National Steel Corp	119813AAI	0042	BOILER HOUSE 1: BOILERS 8 TO 10	355.94	118.07	12.13	0.35
ILLINOIS	National Steel Corp	119813AAI	0044	BOILER HOUSE 2: BOILER #11 - BLAST FURNACE DEPT	420.11	139.35	14.31	0.41
ILLINOIS	National Steel Corp	119813AAI	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	504.43	167.32	17.18	0.49
ILLINOIS	National Steel Corp	119813AAI	0122	SLAB FURNACE #2	166.62	55.27	5.68	0.16
ILLINOIS	National Steel Corp	119813AAI	0123	SLAB FURNACE #3	156.14	51.79	5.32	0.15
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	001	BEDDING PLANT MATL TRANS	0	0	0.42	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	002	SINTER MIXING DRUM	0	0	1.17	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	003	SINTER WINDBOX	1733.82	1274.19	184.56	307.82
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	004	SINTER MISC MATL HANDLING	0	0	126.24	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	005	SINTER TRANSFER STATIONS	0	0	0.93	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	006	BLAST FURNACE CAR DUMPER	0	0	1.48	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	007	BLAST FURNCE THAW SHED	0.01	1.4	0.05	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	008	BF C STOCKHOUSE	0	0	7.17	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	009	BF D STOCKHOUSE	0	0	7.12	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	010	BF C CASTHSE, STOVES, FLR	946.76	492.4	71.35	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	011	BF D CASTHSE, STOVES, FLR	859.54	317.04	62.39	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	036	COAL PREPARATION	0	0	0.12	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	037	BATTERY #1 PUSHING	0	11.42	40.3	5.78
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	039	COKE OVEN UNDRFIRE BAT #1	1569.36	3363.5	82.43	84.16

TABLE 2.2 LADCO BART CATEGORY 6 (IRON AND STEEL PLANTS) EMISSION UNITS (CONTINUED)

STATE	SOURCE NAME	SOURCE ID	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	040	COKE BATTERY #1 QUENCHING	0	0	13.73	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	041	BATTERY #2 PUSHING	0	11.83	21.8	5.8
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	043	COKE OVEN UNDRFIRE BAT #2	1687.12	164.7	99.95	68.72
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	044	BATTERY #2 QUENCHING	0	0	27.73	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	045	COKE OVEN COAL CHEM PLANT	0	0	0	2.29
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	046	COKE SCREENING	0	0	1.39	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	048	CSM #1 PICKLE LINE	0	0	33.71	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	049	CSM #2 PICKLE LINE	0	0	45.41	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	051	COLD SHEET MILL- TANDEM	0	0	40.23	114.61
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	052	BATCH ANNEAL FURNACES	0.23	36.13	1.84	1.24
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	056	COLD SHEET MILL-DUO MILL	0	0	0	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	057	COLD SHEET TEMPER MILL	0	0	0	4
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	058	COLD SHEET SHIP BLDGS 1&2	0	0	0	98.08
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	061	CSM EGL LINE CLEANING	0	0	0	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	062	CSM EGL LINE PICKLING	0	0	0	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	063	CSM EGL LINE ZINC PLATING	0	0	0	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	067	NORTH BURNING BED	0	0	3.24	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	068	SOUTH BURNING BED	0	0	0.68	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	069	HAND SCARFING BED	0	0	7.05	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	070	HOT STRIP MILL FURN #1	155.45	491.57	7.14	3.07

TABLE 2.2 LADCO BART CATEGORY 6 (IRON AND STEEL PLANTS) EMISSION UNITS (CONTINUED)

STATE	SOURCE NAME	SOURCE ID	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	071	HOT STRIP MILL FURN #2	163.94	486.44	7.13	2.89
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	072	HOT STRIP MILL FURN #3	121.88	473.57	6.72	2.9
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	073	HSM ROLLING PROCESS	0	0	2.12	39.16
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	076	POWER STATION BOILER #8	845.63	210.72	20.62	40.86
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	077	POWER STATION BOILER #9	863.28	212.25	20.89	42.2
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	078	POWER STATION BOILER #10	763.91	205.45	19.81	27.22
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	079	POWER STATION BOILER #11	801.38	197.39	19.33	39.94
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	080	POWER STATION BOILER #12	818.65	181.85	18.26	43.14
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	081	#1 ROLL SHOP N. BAGHOUSE	0	0	0.11	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	082	#1 ROLL SHOP S. BAGHOUSE	0	0	0.03	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	083	#2 ROLL SHOP BAGHOUSE	0	0	0.09	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	084	36 SOAKING PITS	0.3	415.72	2.46	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	085	SLAB MILL SCARFER	0	0	71.62	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	086	SLAB MILL ROLLING PROCESS	0	0	2.02	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	088	SLAB YD 3 FURNACE 4&5&6	0.01	2.8	0.1	0.06
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	089	SLAB YD 3 SCARFING BED 3	0	0	9.72	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	091	SLAB YD 3 FLAME CUTTING	0	0	0.52	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	092	SLAB YD 2 FURNACE 1&2&3	0	1.12	0.04	0.02
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	093	SLAB YD 2 FLAME CUT BED 2	0	0	1.73	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	094	SLAB YD 2 SCARFING BED 2	0	0	3.55	0

TABLE 2.2 LADCO BART CATEGORY 6 (IRON AND STEEL PLANTS) EMISSION UNITS (CONTINUED)

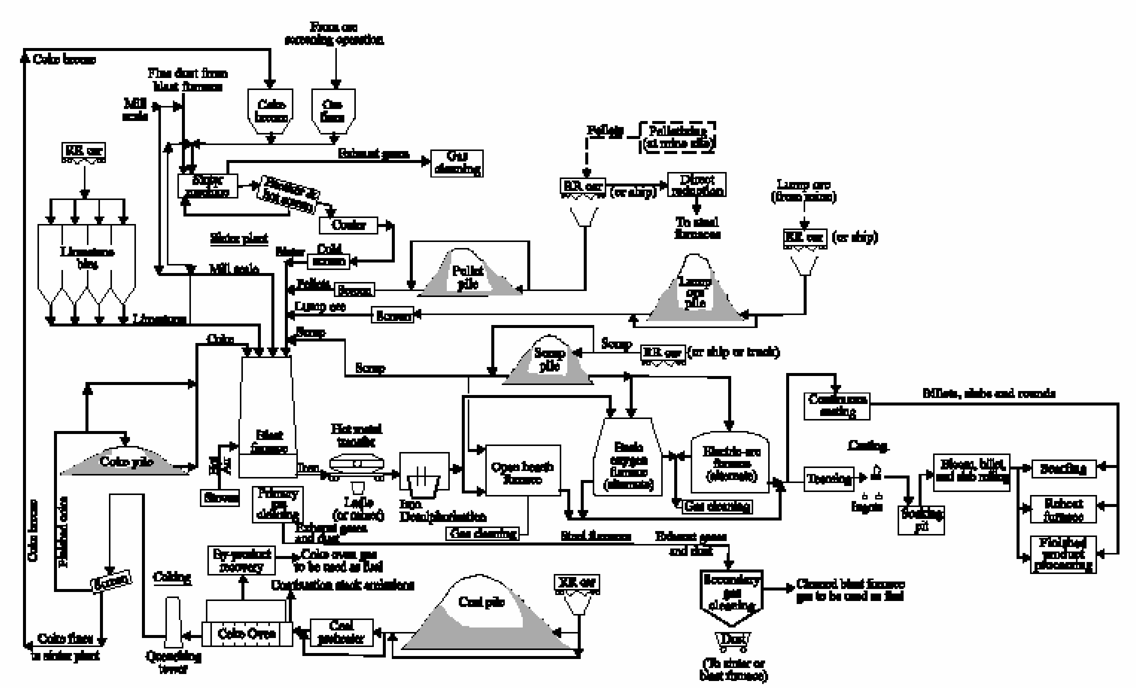
STATE	SOURCE NAME	SOURCE ID	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	095	160"PLATE CONT.FURNACE #1	105.79	105.22	2.91	0.7
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	096	160"PLATE CONT FURNACE #2	86.65	113.82	2.93	0.73
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	097	160"PLATE BATCH FURNCE #4	0	0	0	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	098	160"PLATE BATCH FURNCE #5	0.68	14	0.51	0.28
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	099	160"PLATE BATCH FURNCE #6	27.75	6.74	0.41	0.11
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	100	160"PLATE BATCH FURNCE #7	132.13	17.31	1.42	0.27
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	101	160"PLATE BATCH FURNCE #8	31.09	4.01	0.33	0.06
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	104	160"PLATE CAR BOTTOM FRNC	0.02	4.63	0.17	0.09
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	105	160"PLATE HARDENING FURNC	0.07	16.63	0.59	0.33
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	106	160"PLATE TEMPERING FURNC	0.03	6.19	0.22	0.12
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	107	160 PLATE MILL ROLLING	0	0	0	13.92
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	108	SLAB YD 1 FLAME CUTTING	0	0	0.37	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	109	110"PLATE CONT FURNACE #1	0.1	48.36	0.85	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	110	110"PLATE CONT FURNACE #2	0.16	49.44	0.84	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	111	EXTRA PROC BLDG FLAME CUT	0	0	0.44	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	113	110 PLATE MILL ROLLING	0	0	0	3.23
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	114	BOF HT MTL DESULF STAT #1	0	2.05	4.4	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	115	BOF HT MTL DESULF STAT #2	0	1.29	4.88	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	117	BOF 1&2 CHRG,TAP,SLAGOFF	0	0	25.8	1.53
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	125	BOF 1 & 2 REFINING CYCLE	0	188.94	9.62	2.46

TABLE 2.2 LADCO BART CATEGORY 6 (IRON AND STEEL PLANTS) EMISSION UNITS (CONTINUED)

STATE	SOURCE NAME	SOURCE ID	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	137	TEEMING POUR MOLDS	0	0	2.31	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	140	TRACK HOPPER	0	0	5.47	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	143	JUNCTION HOUSE H1	0	0	1.16	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	144	JUNCTION HOUSE H2	0	0	0.82	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	145	BOF 1 & 2 STORAGE BINS	0	0	1.34	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	148	BOF WEIGH HOPPERS	0	0	1.62	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	153	CONTINUOUS CASTER #1	0	0	0.14	14.21
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	155	CASTER #1 SLAB PROCESSING	0	0	0.53	0
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	00001	157	CASTER BLDGS MISC ACTIVTS	0	0	1.68	0

Figure 2.1 shows a process flow diagram of an iron and steel plant. The process flow diagram (taken from AP-42) shows all types of furnaces including electric arc furnaces. None of the sources in the LADCO region appear to be minimills.

FIGURE 2.1. IRON AND STEEL PLANT PROCESS FLOW DIAGRAM.



The major iron and steel plant operations shown in Figure 2-1 are: (1) coke production, (2) sinter production, (3) iron production, (4) iron preparation, (5) steel production, (6) semifinished product preparation, (7) finished product preparation, (8) heat and electricity supply, and (9) handling and transport of raw, intermediate, and waste materials. The relationships between these operations is shown in Figure 2.1.

As Tables 2.1 and 2.2 indicate, the majority of SO_2 and NO_x emissions are associated with the boilers, furnaces and other types of process heaters involved in coke production, sinter production, and iron and steel production.

Coke used for metallurgical processes is produced by destructively distilling coal in coke ovens. The coal is heated in an oxygen-free atmosphere (–coked–) to remove the majority of the volatile components. The residual material is known as coke. Metallurgical coke is used in iron and steel industry processes (primarily in blast furnaces) to reduce iron ore to iron. Over 90 percent of the total coke production in the United States is dedicated to blast furnace operations. The remaining 10 percent is foundry coke which uses a different blend of coking coals, longer coking times, and lower coking temperatures relative to those used for metallurgical coke to produce the final product. Foundry coke is used in foundry furnaces for melting metal and in the preparation of molds. Coke plants are generally collocated with iron and steel production facilities, and the demand for coke generally corresponds with their production levels. There has been a steady decline in the number of coke plants over the past several years for many reasons, including a decline in the demand for iron/steel, increased production of steel by mini-mills (electric arc furnaces that do not use coke), and the lowering of the coke:iron ratio used in the blast furnace (e. g., increased use of pulverized coal injection).

Sintering is a process that converts fine raw materials (iron ore, coke breeze, limestone, mill scale, and flue dust) into an agglomerated product, sinter, in a size that is conducive for charging into the blast furnace. The raw materials are sometimes mixed with water to provide a cohesive matrix, and then placed on a continuous, traveling grate called the sinter strand. A burner hood, at the beginning of the sinter strand ignites the coke in the mixture, after which the combustion is self supporting and it provides sufficient heat, 1300 to 1480°C (2400 to 2700°F), to cause surface melting and agglomeration of the mix. The burner hood and the combustion of the sinter mixture is the predominant source of gaseous emissions from this process. Underneath the sinter strand is a series of windboxes that draw combusted air down through the material bed into a common duct, generally leading to a gas cleaning device. At the end of the sinter strand, the fused product is discharged where it is crushed and screened. Undersize sinter is recycled to the mixing mill and back to the strand. Following the crushing and screening, the sinter product is cooled in open air or in a circular cooler with water sprays or mechanical fans. It is then crushed and screened for a final time and the appropriately sized material is sent to be charged in the blast furnace. About 2.5 tons of raw materials, including water and fuel, are required to produce 1 ton of product sinter.

Iron is produced in blast furnaces by the reduction of iron bearing materials with a hot gas in a large, refractory lined furnace. The furnace is charged through its top with iron as ore, pellets, and/or sinter; flux as limestone, dolomite, and sinter; and coke for fuel. Iron oxides, coke and fluxes react with the blast air to form molten reduced iron, carbon monoxide (CO), and slag. While the molten iron and slag are collected in a hearth at the base of the furnace, the byproduct gas is collected through offtakes located at the top of the furnace and is recovered for use as fuel. The production of 1 ton of iron requires 1.4 tons of ore or other iron bearing material; 0.5 to 0.65 tons of coke; 0.25 tons of limestone or dolomite; and 1.8 to 2.0 tons of air. Byproducts consist of 0.2 to 0.4 tons of slag, and 2.5 to 3.5 tons of blast furnace gas containing up to 100 pounds (lb) of dust.

The molten iron and slag are removed, or cast, from the furnace on a periodic basis. The casting process begins by drilling a hole, called the taphole, into the clay-filled iron notch at the base of the hearth. The molten iron then flows into runners that lead to transport ladles. Separate runners are used to direct flows of slag from the furnace to a slag pit adjacent to the casthouse, or into slag pots for transport to a remote slag pit. At the conclusion of the cast, the taphole is replugged with clay. The area around the base of the furnace, including all iron and slag runners, is enclosed by a casthouse. The byproduct gas collected at the top of the furnace contains CO and particulate. Because of its high CO content, the blast furnace gas has a low heating value, about 75 to 90 BTU/ft^3, and is used as a fuel within the steel plant. Before it can be fired however, the gas must be cleaned of particulate. Initially, the gases pass through a settling chamber or dry cyclone to remove about 60 percent of the particulate. Next, the gases undergo a 1- or 2-stage cleaning operation, typically a wet scrubber (for a single stage cleaner), which removes about 90 percent of the remaining particulate. If a 2-stage cleaner is used, the secondary cleaner is typically a high-energy wet scrubber (usually a venturi) or an electrostatic precipitator, either of which can remove up to 90 percent of the particulate that eludes the primary cleaner. Together these control devices provide a clean fuel of less than 0.02 grains per cubic foot [g/ft^3]. A portion of this gas is fired in the blast furnace stoves to preheat the blast air, and the rest is used in other plant operations.

Sulfur in the molten iron is sometimes reduced before charging into the steelmaking furnace by adding reagents. This is known as hot metal desulfurization. The reagents cause a reaction that results in floating slag which can be skimmed off. Desulfurization may be performed in the hot metal transfer (torpedo) car at a location between the blast furnace and basic oxygen furnace (BOF), or it may be done in the hot metal transfer (torpedo) ladle at a station inside the BOF shop. Typically the reagents used for the reaction are powdered calcium carbide (CaC_2) and calcium carbonate ($CaCO_3$) or salt-coated magnesium granules. Powdered reagents are injected into the metal through a lance with high-pressure nitrogen. The process duration varies with the injection rate, hot metal chemistry, and desired final sulfur content, and is in the range of 5 to 30 minutes.

Steel is typically made using basic oxygen furnaces (BOF) which employee the basic oxygen process (BOP). In the BOP, molten iron from a blast furnace and iron scrap are refined in a furnace by lancing (or injecting) high-purity oxygen. The input material is typically 70 percent molten metal and 30 percent scrap metal. The oxygen reacts with carbon and other impurities to remove them from the metal. Since the reactions are exothermic, no external heat source is required to melt the scrap and to raise the temperature of the metal to the desired range for tapping. The large quantities of CO produced by the reactions in the BOF can be controlled by combustion at the mouth of the furnace and then vented to gas cleaning devices, as with open hoods, or combustion can be suppressed at the furnace mouth, with closed hoods. BOP steelmaking is conducted in large (up to 400 ton capacity) refractory lined pear shaped furnaces. There are 2 major variations of the BOP. In conventional BOFs, oxygen is blown into the top of the furnace through a water-cooled lance. In the newer, Quelle Basic Oxygen process (Q-BOP), oxygen is injected through tuyeres located in the bottom of the furnace. A typical BOF cycle consists of the scrap charge, hot metal charge, oxygen blow (refining) period, testing for temperature and chemical composition of the steel, alloy additions and reblows (if necessary), tapping, and slagging. The full furnace cycle typically ranges from 25 to 45 minutes.

Steel can also be made using electric arc furnaces (EAF). EAFs are normally used to produce carbon and alloy steels. The input material to an EAF is typically 100 percent scrap. Cylindrical, refractory lined EAFs are equipped with carbon electrodes to be raised or lowered through the furnace roof. With electrodes retracted, the furnace roof can be rotated aside to permit the charge of scrap steel by overhead crane. Alloying agents and fluxing materials usually are added through doors on the side of the furnace. The electrodes generate heat by having electric current of opposite polarities pass through each electrode. After melting and refining periods, the slag and steel are poured from the furnace by tilting. The production of steel in an EAF is a batch process. Cycles, or "heats", range from about 1-1/2 to 5 hours to produce carbon steel and from 5 to 10 hours or more to produce alloy steel. Scrap steel is charged to begin a cycle, and alloying agents and slag materials are added for refining. Stages of each cycle normally are charging and melting operations, refining (which usually includes oxygen blowing), and tapping.

Steel may also be made using open hearth furnaces (OHF), which are shallow, refractory-lined basins in which scrap and molten iron are melted and refined into steel. The furnace is charged with scrap through doors in the furnace front. Hot metal from the blast furnace is added by pouring from a ladle through a trough positioned in the door. The mixture of scrap and hot metal can vary from all scrap to all hot metal, but typically a half-and-half mixture is most common. The heat for melting is provided by gas burners above and at the side of the furnace. Refining is accomplished by the oxidation of carbon in the metal and the formation of a limestone slag to remove impurities. Most furnaces are equipped with oxygen lances to speed up melting and refining. The steel product is tapped by opening a hole in the base of the furnace with an explosive charge. The open hearth steelmaking process with oxygen lancing normally requires from 4 to 10 hours for each heat.

Once the steel has been tapped from a furnace, the molten metal is poured (teemed) into ingots which are later heated and formed into other shapes, such as blooms, billets, or slabs. The molten steel may bypass this entire process and go directly to a continuous casting operation. Whatever the production technique, the blooms, billets, or slabs undergo a surface preparation step, scarfing, which removes surface defects before shaping or rolling. Scarfing can be performed by a machine applying jets of oxygen to the surface of hot semifinished steel, or by hand (with torches) on cold or slightly heated semifinished steel.

For fuel fired sources at iron and steel plants, control technology options identified for SO_2 include advanced flue gas desulfurization (AFGD), dry FGD, and wet FGD; control technology options for NO_x

include low NO_x burners (LNB), LNB with flue gas recirculation (FGR), LNB with selective non-catalytic reduction (SNCR), ultra-low-NO_x burners (ULNB), ULNB with selective catalytic reduction (SCR), and SCR by itself, depending upon the source type. For PM emissions, dust collectors (DC), fabric filters (FF), fabric filters with traveling hoods, wet electrostatic precipitators (WESP), and dry electrostatic precipitators (DESP) were considered. In addition for some of the PM only sources that are primarily fugitive in nature, enclosures (EC) were also identified as PM controls. Table 2.3 indicates the pollutant controls identified for each process at iron and steel plants by pollutant for the three primary controls (where available).

Similarly to our treatment of industrial boilers subject to BART, in cases where the emission unit had more than one fuel type (segment) the primary fuel was used to develop cost estimates. Where similar sources (e.g., process heaters) fired different fuels and each fuel was used as a primary fuel for at least one emission unit, MACTEC prepared separate cost estimates for each fuel type.

TABLE 2.2 THREE CONTROL TECHNOLOGY OPTIONS IDENTIFIED FOR IRON AND STEEL PLANT EMISSION UNITS (WHERE AVAILABLE).

SCC	SCC_L4 DESPCRITION	Technology 1	Technology 2	Technology 3	Pollutant
10200707	Coke Oven Gas	ULNB+SCR	SCR	LNB+FGR	NOx
30300699	Other Not Classified	ULNB+SCR	SCR	LNB	NOx
30390002	Residual Oil: Process Heaters	ULNB	LNB+SNCR	LNB	NOx
30390003	Natural Gas: Process Heaters	ULNB+SCR	SCR	LNB	NOx
30390004	Process Gas: Process Heaters	ULNB+SCR	SCR	LNB	NOx
10200707	Coke Oven Gas	FF	DC	DESP	PM
30300302	Oven Charging	BAGHOUSE WITH TRAVELING HOOD			PM
30300304	Quenching	BAGHOUSE WITH TRAVELING HOOD			PM
30300699	Other Not Classified	FF	DC	DESP	PM
30300825	Cast House	FF	DC	DESP	PM
30300913	Basic Oxygen Furnace: Open Hood-Stack	FF	DC	DESP	PM
30300915	Hot Metal (Iron) Transfer to Steelmaking Furnace	FF	DC	DESP	PM
30300931	Hot Rolling	FF	DC	DESP	PM
30300932	Scarfing	FF	DC	DESP	PM
30300936	Coating: Tin, Zinc, etc.	FF	DC	DESP	PM
30301502	Sintering: Raw Materials Handling	EC			PM
30301504	Sintering: Discharge End	EC			PM
30390002	Residual Oil: Process Heaters	FF	DC	WESP	PM
10200707	Coke Oven Gas	AFGD	Dry FGD	Wet FGD	SO2
30300931	Hot Rolling	AFGD	Dry FGD	Wet FGD	SO2
30300936	Coating: Tin, Zinc, etc.	AFGD	Dry FGD	Wet FGD	SO2
30390002	Residual Oil: Process Heaters	AFGD	Dry FGD	Wet FGD	SO2
30390004	Process Gas: Process Heaters	AFGD	Dry FGD	Wet FGD	SO2

NO_x Emission Control Options

Integrated iron and steel mills typically produce steel by reducing iron ore to iron in a blast furnace followed by removal of excess carbon and other impurities from the iron in a basic oxygen furnace. Other processes involve pelletizing iron ore, recycling of iron-bearing materials (e.g., sintering), coke-making, and steel finishing processes such as shaping, annealing, and galvanizing. All of these are high temperature processes which usually involve the combustion of fossil fuels, and all are potential sources of NO_x emissions. The following iron and steel processes are all specifically capable of generating NO_x:

- Coke oven underfiring - a high-temperature process with NO_x emissions from coke oven gas (COG), natural gas (NG), and/or blast furnace gas (BFG).
- Sinter plant - iron ore fines, coke fines, other iron-bearing materials, and (often) flux are well-mixed and spread uniformly on a traveling grate and ignited, typically with NG.
- Blast furnace – while the blast furnace itself is a closed system with no atmospheric emissions, each blast furnace typically has three or four associated stoves that preheat the air blast supplied to the blast furnace. Because these stoves are heated primarily with BFG, NO_x emissions from the stoves generally have low concentrations.
- Charging – during charging, combustible off-gases are generated. Generally these are collected by hoods and then burned (frequently in flares). During the combustion of the off-gas, thermal NO_x is generated.
- Electric arc furnace steelmaking - the use of electricity for steel melting transfers the generation of NO_x from the iron and steel mill to a utility generating plant, however, oxygen and NG are sometimes used to preheat the charge. Thus EAF's are potential NO_x emission sources.
- Molten steel processing - slabs, billets, and blooms may be reheated to suitable working temperatures in reheat furnaces prior to being passed through mills for further shaping. Ingots are typically reheated in soaking pits prior to subsequent processing. Reheat furnaces and soaking pits are high-temperature, fossil fuel (typically natural gas) burning furnaces and are sources of NO_x emissions.
- Finishing processes - annealing and galvanizing also involve reheating steel products to suitable temperatures for processing. Consequently, these finishing processes are also sources of NO_x emissions.

There are three fundamentally different mechanisms of NO_x formation. These mechanisms yield (1) thermal NO_x, (2) fuel NO_x, and (3) prompt NO_x. The thermal NO_x mechanism arises from the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in combustion air. The fuel NO_x mechanism arises from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. The prompt NO_x mechanism involves the intermediate formation of hydrogen cyanide (HCN), followed by the oxidation of HCN to NO_x. Natural gas and most distillate oils have no chemically bound fuel nitrogen and essentially all NO_x formed from the combustion of these fuels is thermal NO_x. Residual oils and coals all have fuel-bound nitrogen and, when these are combusted, NO_x is formed by all three mechanisms. Iron and steel mill processes tend to use gaseous fuels, i.e., NG, COG, BFG, and oxygen, and the NO_x generation tends to be thermal NO_x. Exceptions include sintering where coke fines are burned as a fuel and coke ovens where coal is destructively distilled in the absence of air. Emissions from sintering and fugitive emissions from coke ovens may be sources of fuel NO_x emissions. Prompt NO_x formation is not a major factor. It forms only in fuel-rich flames, which are inherently low NO_x emitters. Thermal NO_x formation is the predominant mechanism of NO_x generation at iron and steel mills.

Very little NO_x emissions data are available in the literature relevant to iron and steel processes. In fact the most current chapter of AP-42 concerning iron and steel processes shows no emission factors for NO_x (or SO_2). The Alternative Control Technology document for NO_x at iron and steel plants (EPA-453/R-94-065) has some limited emissions data. In that report the highest emissions are found for regenerative annealing and galvanizing furnaces. Significant emissions are also found for coke-oven underfiring, sintering, and reheat furnaces. Emission factors that range from 0.021-1.2 lb/MMBtu were found for these sources.

At the time the EPA's ACT NO_x document was published (1994) few emission units found at iron and steel plants had NO_x controls. For many emission unit types, a suitable control technique had not been demonstrated. At that time, this included emission units such as sinter plants, coke ovens, blast furnace stoves, and steelmaking furnaces. Emission processes at iron and steel plants known to have NO_x controls applied at the time of the ACT document publication were reheat furnaces, annealing furnaces, and galvanizing furnaces. Control techniques known to have been applied to these processes are as follows:

Reheat furnaces	Low excess air (LEA)
	LNB
	LNB w/ FGR
Annealing furnaces	LNB
	LNB w/FGR
	SCR
	LNB plus SCR
Galvanizing furnaces	LNB
	LNB w/FGR.

As with most fuel fired NO_x sources, there are two broad categories of NO_x reduction techniques: 1) process controls, including combustion modifications, that rely on reducing or inhibiting the formation of NO_x in the production process (generally through the use of some type of combustion control on the fuel fired emission unit); and 2) post-combustion (secondary) controls, where flue gases are treated to remove NO_x that has already been formed.

For iron and steel plants, six different control technologies or control technology combinations were evaluated for NO_x emissions from fuel fired emission units at iron and steel plants. These technologies are: low NO_x burners, low NO_x burners with FGR, low NO_x burners with SNCR, ultra-low NO_x burners, ultra-low NO_x burners with SCR and SCR. These technologies provide both combustion or post-combustion controls (or a combination of both). Background information on each of these individual technologies (e.g., ULNB) is provided below.

Flue Gas Recirculation

Flue gas recirculation (FGR) uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The flue gas for the FGR system is usually taken from the main flue gas flow downstream of the economizer. A fan (blower) is needed to withdraw the required amount of flue gas. This system is usually called Flue Gas Recirculation (FGR). In some cases, this type system is referred to as "External Flue Gas Recirculation (EFGR)" or "Forced Flue Gas Recirculation". This differentiation is made because sometimes the flue gas for FGR is taken from the flue gas flow upstream of the stack using the forced draft (FD) fan instead of a separate FGR fan. This system is called "Induced Flue Gas Recirculation (IFGR)". In either system, the flue gas is mixed with the combustion air and this mixture is introduced into the burner. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures; which in turn reduces NO_x emissions. When operated without additional controls, the normal NO_x control efficiency range for FGR is 30 percent to 50 percent. When coupled with low-NO_x burners (LNB) the control efficiency increases to 50-72 percent.

Low-NO_x Burners

Low-NO_x burner (LNB) technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. A LNB is a staged combustion process that is designed to split fuel combustion into two zones, primary combustion and secondary combustion.

Two general types of low NO_x burners exist, staged fuel and staged air. MACTEC utilized the staged fuel design in the cost analysis because lower emission rates can be achieved with a staged fuel burner than with a staged air burner. Staged fuel LNBs separate the combustion zone into two regions. The first region is a lean primary combustion region where the total quantity of combustion air is supplied with a fraction of the fuel. Combustion in the primary region (first stage) takes place in the presence of a large excess of oxygen at substantially lower temperatures than a standard burner. In the second region, the remaining fuel is injected and combusted with any oxygen left over from the primary region. The remaining fuel is introduced in the second stage outside of the primary combustion zone so that the fuel/oxygen are mixed diffusively (rather than turbulently) which maximizes the reducing conditions. This technique inhibits the formation of thermal NO_x, but has little effect on fuel NO_x. Thus staged fuel LNBs are particularly well suited for coal and natural gas fired emissions units which are higher in thermal NO_x than for fuel oils which are higher in fuel NO_x. For fuel oil fired emissions units, the staged air LNBs are generally preferred. By increasing residence times staged air LNBs provide reducing conditions which has a greater impact on fuel NO_x than staged fuel burners. The estimated NO_x control efficiency for LNBs in high temperature applications is 25 percent. However when coupled with FGR or selective non-catalytic reduction (SNCR) these efficiencies increase to 50-72 and 50-89 percent, respectively.

Ultra-low NO_x Burners

These burners may incorporate a variety of techniques including induced flue gas recirculation (IFGR), steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and low-NO_x burner control technologies. Rather than a system of fans and blowers (like FGR), the burner itself is designed to recirculate hot, oxygen depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency. Because of this reduction in temperature, ULNB would likely only be applicable to processes at iron and steel plants that are not temperature dependent, unless the reduction in flame temperature doesn't fall below the required threshold temperature for the process. Reduced oxygen concentrations in the flame have a strong impact on fuel NO_x so ULNBs are an effective NO_x control for fuel firing equipment that fire fuel oil. The estimated NO_x control efficiency for ULNBs in high temperature applications is 50 percent. Newer designs have yielded efficiencies of between 75-85 percent. When coupled with selective catalytic reduction, efficiencies in the range of 85-97 percent can be obtained.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a post-combustion NO_x control technology in which ammonia (NH_3) is injected into the post-combustion gas stream in the presence of a catalyst. A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO_x decomposition. NO_x is removed through the following chemical reaction:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

The reaction of NH_3 and NO_x is favored by the presence of excess oxygen. However, the primary variable affecting NO_x reduction is temperature. Optimum NO_x reduction occurs at catalyst bed temperatures of 600–750 °F for conventional (vanadium or titanium based catalysts) and 470–510 °F for platinum catalysts. A high temperature zeolite catalyst is also available; it can operate in the 600–1000 °F temperature range. A given catalyst typically provides optimal performance within ± 50 °F of its design temperature for applications in which flue gas oxygen concentrations are greater than 1 percent. Below this optimum range, the catalyst activity is greatly reduced allowing unreacted NH_3 to slip through (ammonia slip). At temperatures above 850°F ammonia begins to oxidize to form additional NO_x. The

NH_3 oxidation to NO_x increases with increasing temperature. The normal NO_x control efficiency range for SCR is 70 percent to 90 percent.

SCR has been extensively and quite successfully used in a very cost effective manner on coal- and gas-fired utility boilers, industrial boilers, gas turbines and internal combustion diesel engines in the United States. There have been few uses of SCR in the iron and steel industry. At the time the EPA's ACT NO_x document was published, Japanese iron and steel mills had been experimenting with SCR for sinter plants and coke ovens, however these efforts at that time were experimental. As indicated above, SCR has been used with annealing furnaces. There are few other references to the use of SCR for NO_x control for other emission processes at iron and steel plants. MACTEC did find one example usage of SCR for controlling sintering plant exhaust gases. Of particular interest in that example installation was the use of iron ore as the catalyst. The benefit of using iron ore as the catalyst was that unlike other types of catalyst which have a solid waste disposal component, the iron ore can be used directly as a steel making raw material, thus obviating the solid waste disposal issue.

In the SCR process, typically, anhydrous ammonia usually diluted with air or steam is injected into hot flue gases, which then pass through a catalyst bed where NO_x is reduced to N_2 gas and water. As indicated above, the optimum temperature for SCR depends on the catalyst. Thus the exit gas temperatures from some of the processes at iron and steel plants may either be too high or too low, requiring either reheat (if too low) or dilution/quenching (if too high) in order to effectively use SCR. Thus careful consideration should be given on a source-specific basis depending on how raw materials are currently processed.

<u>Selective Non-Catalytic Reduction</u>

In the selective non-catalytic reduction (SNCR) process, urea or ammonia-based chemicals are injected into the flue gas stream to convert NO to N_2 and water. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The reaction with urea is as follows:

$$2NO + CO(NH_2)_2 + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2\ H_2O$$

The optimum operating temperature for SNCR is 1,600°F to 2,100°F. Under these temperature conditions a significant reduction in NO_x occurs. At temperatures above 2,000°F an alternative reaction occurs and NO_x control efficiency decreases rapidly. The normal NO_x control efficiency range for SNCR is 50 percent to 70 percent. To date there are no known installations of SNCR at iron and steel plants. While there are not any known installations, there should be no reason that SNCR couldn't be used for some operations within an iron and steel plant.

<u>Site-specific Measures</u>

Site-specific measures may also be employed to reduce NO_x emissions. Under this option, facility operators would evaluate the impact of fuels on NO_x emission rates. Generally an evaluation of the impacts of fuels would result in an evaluation of fuel switching. Fuel switching is less likely in the iron and steel industry since much of the fuel used is gaseous, and in several instances is the use of byproduct fuels (e.g., blast furnace gas). Switching to coal or oil may not be an option for iron and steel plants and will likely result in substantial increases in SO_2 emission levels. For this analysis we have not directly considered fuel switching as an alternative to add on controls. However there may be certain processes at specific sites that could see potential cost savings by fuel switching resulting in a single type of control rather than controls for several visibility impairing pollutants. If this option is employed, increases in other pollutant emissions should be compared to the emission reductions achieved for the current fuel in order to identify the best net reduction in visibility impairing pollutants.

SO_2 Emission Control Options

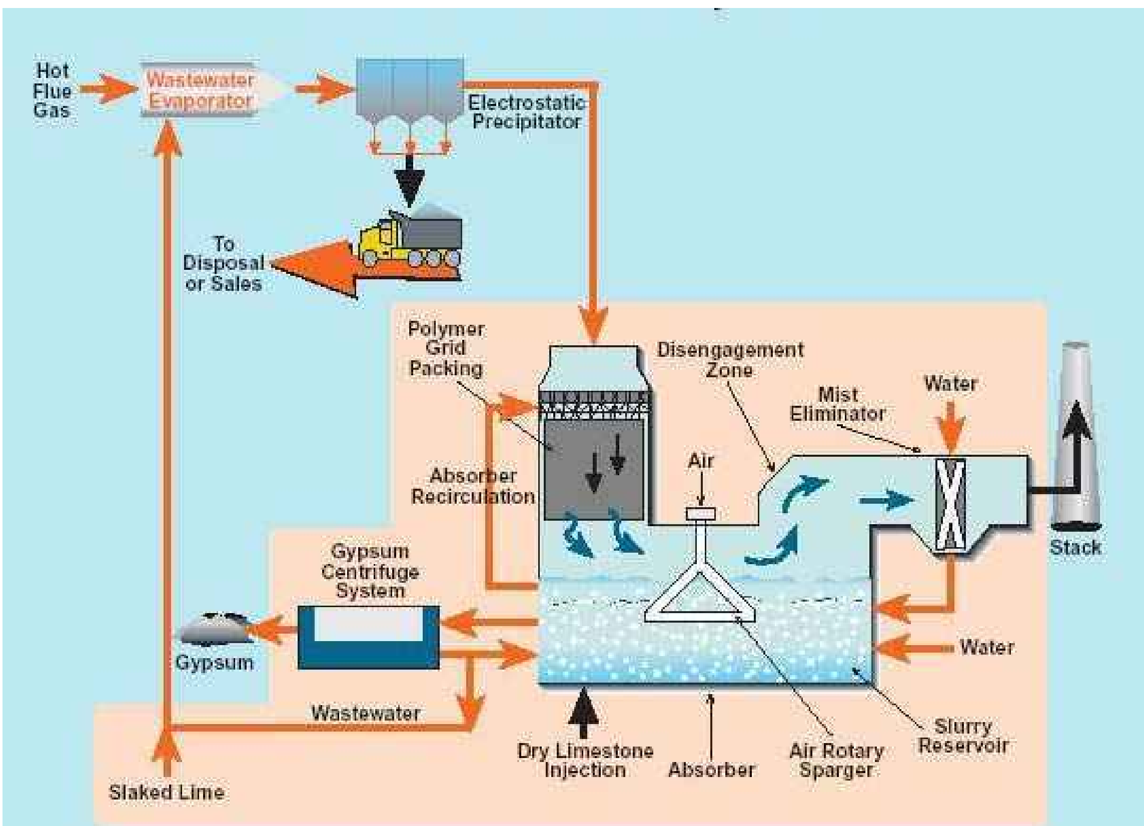
Sulfur dioxide may be generated both from the sulfur compounds in the raw materials and from sulfur in the fuel. The sulfur content of both raw materials and fuels varies from plant to plant and with geographic location. With that said, MACTEC has been unable to find a single instance of installed SO_2 controls at iron and steel plants. Part of the reason for this is because with few exceptions, the fuel fired processes at iron and steel plants generally use a gaseous fuel (natural gas, blast furnace gas, etc.). The main SO_2 emitting processes at the LADCO facilities evaluated in this work were sinter windboxes, coke underfiring, and boilers and process heaters firing either process gas or blast furnace gas. In general (especially for process heaters and boilers), typical SO_2 controls could be utilized for control of SO_2.

The three control technologies evaluated for SO_2 emissions from iron and steel plants were: 1) advanced flue gas desulfurization (AFGD), 2) wet flue gas desulfurization, and 3) dry flue gas desulfurization (spray dryer absorption). A brief description of each of these technologies is provided below.

Advanced Flue Gas Desulfurization

The AFGD process accomplishes SO_2 removal in a single absorber which performs three functions: prequenching the flue gas, absorption of SO_2, and oxidation of the resulting calcium sulfite to wallboard-grade gypsum. Figure 2.2 shows the process flow for an AFGD system.

FIGURE 2.2 ADVANCED FLUE GAS DESULFURIZATION PROCESS FLOW



Incoming flue gas is cooled and humidified with process water sprays before passing to the absorber. In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator.

As the flue gas contacts the slurry, the sulfur dioxide is absorbed, neutralized, and partially oxidized to calcium sulfite and calcium sulfate. The overall reactions are shown in the following equations:

$CaCO_3 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H_2O + CO_2$
$CaSO_3 \bullet 1/2\ H_2O + 3H_2O + O_2 \rightarrow 2\ CaSO_4 \bullet 2\ H_2O$

After contacting the flue gas, slurry falls into the slurry reservoir where any unreacted acids are neutralized by limestone injected in dry powder form into the reservoir. The primary reaction product, calcium sulfite, is oxidized to gypsum by the air rotary spargers, which both mix the slurry in the reservoir and inject air into it. Fixed air spargers assist in completing the oxidation. Slurry from the reservoir is circulated to the absorber grid.

A slurry stream is drawn from the tank, dewatered, and washed to remove chlorides and produce wallboard quality gypsum. The resultant gypsum cake contains less than 10 percent water and 20 ppm chlorides. The clarified liquid is returned to the reservoir, with a slipstream being withdrawn and sent to the wastewater evaporation system for injection into the hot flue gas ahead of the electrostatic precipitator. Water evaporates and dissolved solids are collected along with the flyash for disposal or sale.

Wet Scrubbing / Flue-Gas Desulfurization

Wet scrubbing techniques are used to control both particulate and SO_2 emissions. Wet scrubbing processes used to control SO_2 are generally termed flue-gas desulfurization (FGD) processes. FGD utilizes gas absorption technology, the selective transfer of materials from a gas to a contacting liquid, to remove SO_2 in the waste gas. Caustic, crushed limestone, or lime are used as scrubbing agents. Our BART screening evaluation assumes that lime is the scrubbing agent. The SO_2 removal reactions for lime are as follows:

$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet 1/2\ H_2O + 1/2\ H_2O$
$Ca(OH)_2 + SO_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \bullet 2\ H_2O$

The reactions when caustic are used are as follows:

$Na^+ + OH^- + SO_2 \rightarrow NaHSO_3$
$2Na^+ + 2OH^- + SO_2 \rightarrow Na_2SO_3 + H_2O$

The reactions for limestone are presented in the AFGR section.

Caustic scrubbing produces a liquid waste, and minimal equipment is needed. When lime or limestone is used as the reagent for SO_2 removal, additional equipment is needed for preparing the lime/limestone slurry and collecting and concentrating the resultant sludge. Calcium sulfite sludge is watery and it is typically stabilized with fly ash for land filling. The calcium sulfate sludge is stable and easy to dewater. To produce calcium sulfate, an air injection blower is needed to supply the oxygen for the second reaction to occur. The normal SO_2 control efficiency range for SO_2 scrubbers is 80 percent to 90 percent for low efficiency scrubbers and 90 percent to 99 percent for high efficiency scrubbers.

While wet scrubbers have been used successfully in the utility industry for control of SO_2 from boilers, they may require more care when used for an iron and steel plant, since the likelihood of additional contaminants in the fuel source is higher. Calcium sulfate scaling and cementitious buildup when a wet scrubber is used for acid gas control are potential problems when high particulate loadings are found in the gas stream. Many of these problems can be avoided however, if these systems are installed downstream of a high efficiency particulate control device (e.g., fabric filter). Failure of the particulate control device can pose difficult problems for a downstream wet scrubber.

Dry Flue Gas Desulfurization (Spray Dryer Absorption)

Spray dryer absorption (SDA) systems spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming $CaSO_3$/$CaSO_4$. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or ESP. When used to specifically control SO_2, the term dry flue-gas desulfurization (dry FGD) may also be used. As with other types of dry scrubbing systems (such as lime/limestone injection) exhaust gases that exit at or near the adiabatic saturation temperature can create problems with this control technology by causing the baghouse filter cake to become saturated with moisture and plug both the filters and the dust removal system. In addition, the lime slurry would not dry properly and it would plug up the dust collection system. However there is some argument in the control community that indicates that some of the SO_2 removal actually occurs on the filter cake. Therefore, dry FGD (spray dryer absorption) may not be technically feasible if exit gas temperatures are not substantially above the adiabatic saturation temperature. For iron and steel plants, these temperatures are likely to be above the adiabatic saturation temperature. If not, a reheater can be applied to the stream to raise the temperature above the adiabatic saturation level.

PM Emission Control Options

Sources of PM at iron and steel plants include (1) sintering, (2) raw material storage, (3) blast furnace, (4) boilers and process heaters, (5) casting and finishing operations, (6) milling, (7) pickling and cleaning operations, and (8) coke production. Some of these sources are PM only sources while others also emit SO_2 and NO_x.

For the LADCO iron and steel sources identified as being BART eligible, the largest emission units are blast furnaces, sintering windboxes, coke underfiring, and scarfing. Particulate control devices for iron and steel plants must be able to clean gases with fairly high dust loadings.

Four general types of control technologies were evaluated for PM emissions from emission units at iron and steel plants: fabric filter (either fixed or attached to traveling hoods), dust collector (cartridge), wet electrostatic precipitator, and dry electrostatic precipitator. All of these control technologies are deemed technically feasible for retrofitting at iron and steel plants, specifically for non-fugitive emission sources.

In addition to the devices identified for non-fugitive emission sources, enclosures were identified as a means of controlling emissions from sintering raw materials handling and from the discharge end of the sintering process. We also look at best management practices as a means of controlling emissions from these two types of sources. Descriptions of each of these controls (fugitive and non-fugitive) are provided below.

Fabric Filter

A fabric filter, or baghouse, is a potential control method for particulate emissions from non-fugitive emission units at iron and steel plants. Many of these facilities are already using fabric filters. The only potential drawback to a fabric filter would be when used in conjunction with a high moisture flue gas stream or with extremely high temperatures. If moisture levels in the flue gas stream are too high then filter caking can occur. A fabric filter, or baghouse, consists of a number of fabric bags placed in parallel inside of an enclosure. Particulate matter is collected on the surface of the bags as the gas stream passes through them. The particulate is periodically removed from the bags and collected in hoppers located beneath the bags. A number of methods are employed to facilitate the removal of particulate from the bags, including shaking, reverse air flow, and pulse air flow. The normal PM control efficiency range for a fabric filter is 95 percent to 99+ percent. A number of emission units at the iron and steel plant emission units identified as potentially subject to BART in the LADCO region already have fabric filters to control particulate emissions.

Dust Collector

Dust collectors are similar to fabric filters in that the air stream is cleaned by passing the stream through a material that acts as a filter. In the case of dust collectors, the filter material is typically a pleated fabric or filter type material. As with fabric filters, the dust is periodically removed, typically by pulsed air jets. The removed particulate is collected in hoppers located beneath the collector. Several factors determine cartridge filter collection efficiency including gas filtration velocity, particle characteristics, filter media characteristics, and cleaning mechanism. The normal PM control efficiency range for a dust collector is in the 99+ percent range.

Cartridge dust collectors do have some limitations however. For example, cartridges are limited in temperature range due to filter media and sealant to approximately 200 ºF. Synthetic non-woven media can be used to a temperature of approximately 400 º F. Higher temperature streams must be cooled to temperatures below these levels using spray coolers or dilution air in order not to damage the cartridges. Minimum temperatures must be kept above the adiabatic saturation temperature in order not to condense materials out. Corrosive streams can also cause problems for the cartridges.

Cartridge filtration systems are generally limited to low flow rate applications. The cartridges also need to operate with a medium pressure drop typically in the range of 100 – 250 mm of water.

Cartridge filtration does have two significant advantages. First the space requirements are significantly lower than those for a baghouse. Second for particles that have low resistivity that would not be handled well by an ESP, cartridges may be an ideal solution.

For iron and steel plants, dust cartridges are likely to only be technically feasible for lower temperature operations or low flow operations.

Dry Electrostatic Precipitator

An electrostatic precipitator (ESP) is a potential control method for particulates from iron and steel plants, especially those from fuel fired equipment. An electrostatic precipitator applies electrical forces to separate suspended particles from the flue gas stream. The suspended particles are given an electrical charge by passing through a high voltage DC corona region in which gaseous ions flow. There are two general types of ESP: wire/plate and wire/pipe types. Further, ESPs come in both wet (see below) and dry configurations. The charged particles are attracted to and collected on oppositely charged collector surfaces. In a dry electrostatic precipitator (DESP) particles on the collector surfaces are released by rapping and fall into hoppers for collection and removal. The normal PM control efficiency range for an ESP is between 90 and 99+ percent with typical values reaching the 98 percent to 99+ percent range.

One of the major advantages of an ESP is that it operates with essentially little pressure drop in the gas stream. As a consequence, energy and operational costs tend to be low (other than electricity to operate the ESP itself). They are also capable of handling high temperature conditions. The major disadvantages of ESPs are their high capital costs and the fact that wire discharge electrodes are a high maintenance item. They are also not well suited for operations that are highly variable due to their sensitivity to gas flow, temperature and particle/gas composition. They also do not handle “sticky” particles well or those that have high resistivities. There may also be the danger of explosion if the gas stream composition is flammable. Relatively sophisticated maintenance personnel are required. Finally, ESPs can take up substantial space in order to achieve the low gas velocities required for efficient particle removal. This may be of concern for retrofit options where space is at a premium.

Wet Electrostatic Precipitator

A wet electrostatic precipitator (WESP) is a potential control method for particulates in boiler flue gas. A WESP operates on the same collection principles as a DESP, and uses a water spray to remove particulate matter from the collection plates. The normal PM control efficiency range for a WESP is 98 percent to 99+ percent. The same advantages and disadvantages that apply to a DESP apply to a WESP with the exception that WESPs can effectively be used to collect "sticky" particles and highly resistive dust. In addition, the wash used in WESPs can also have some control effect on other pollutant gases via absorption and can help condense other emissions due to the cooling of the stream by the wash.

Enclosures

An enclosure is a potential control method for particulate emissions from material handling sources such as mills, grinders, conveyors, etc.. Enclosures, either partial or complete, surround the source as much as possible without interfering with the process operations. Enclosures prevent particulate matter from becoming airborne as a result of disturbance created by ambient winds or by mechanical entrainment resulting from the operation of the source causing the emissions. The normal PM control efficiency range for an enclosure is 50 percent to 100 percent.

Partial enclosures are sometimes combined with wet suppression techniques to provide slightly higher control efficiencies. In general partial enclosures with wet suppression PM control efficiencies are generally towards the top end of the wet suppression alone.

Wet Suppression

Although wet suppression wasn't specifically identified as a potential control method for particulate matter emitted from material handling and other fugitive PM sources at iron and steel plants, certain emission units at LADCO plants already use wet suppression for PM control. In general, wet suppression systems apply either water or water containing a chemical surfactant or foaming agent to the surface of the particulate generating material. The chemical surfactant or foaming agent agglomerates and binds the particulates to the aggregate surface thus eliminating or reducing its emission potential. Care must be taken when using surfactant or foaming agents to insure that their use doesn't compromise the product requirements. In addition, wet suppression can only be used where the final usage of the product does not require a dried product, unless drying occurs as part of the process. The normal PM control efficiency range for wet suppression is 50 percent to 75 percent.

Best Management Practices

Although not specifically identified by MACTEC as a control, PM emissions can also be controlled via "best management practices" (BMP). Best management practices are preventative measures that minimize the release of particulate matter into the environment. Best management practices may include the proper design and maintenance of equipment, good housekeeping, and good operating practices such as using telescopic chutes (basically a form of enclosure) for loading and unloading procedures, limiting drop heights, covering truck beds, and orienting storage piles perpendicularly to prevailing winds to reduce the exposed surface (and thus the emissions). The PM control efficiency range for best management practices varies depending upon the application.

Close scrutiny should be given to these type processes at iron and steel plants to determine if BMP can be used to help control PM emissions at iron and steel facilities.

Effect of the NESHAP on PM Controls

PM controls are specified in the NESHAP for iron and steel plants. Thus if the facility is considered "major" for HAPS, then PM controls will be required for certain sources within iron and steel plants.

The PM emission limits for a sinter windbox exhaust stream are 0.4 pounds per ton (lb/ton) of product sinter for an existing sinter plant and 0.3 lb/ton for a new sinter plant. The final rule limits PM emissions from a discharge end to 0.02 grains per dry standard cubic foot (gr/dscf) for an existing plant and 0.01 gr/dscf for a new plant. The discharge end PM limits are a flow-weighted average when multiple control devices are operated in parallel. A 20 percent opacity limit applies to fugitive emissions from a discharge end at an existing sinter plant; a 10 percent opacity limit applies to a new sinter plant (both are 6-minute averages). The PM emission limits for sinter cooler stacks are 0.03 gr/dscf for an existing plant and 0.01 gr/dscf for a new plant. If the sinter cooler is vented to the same control device as the discharge end, the PM limit is 0.02 gr/dscf for an existing plant and 0.01 gr/dscf for a new plant.

For blast furnaces the PM emission limits for a control device applied to emissions from a casthouse are 0.01 gr/dscf for an existing blast furnace and 0.003 gr/dscf for a new blast furnace. The opacity limits for fugitive emissions from a casthouse are 20 percent for an existing blast furnace and 15 percent for a new blast furnace (both are 6-minute averages).

For primary emissions from a basic oxygen process furnace (BOPF), different PM emission limits apply based on the type of hood system (closed or open). For BOPF with closed hood systems at a new or existing BOPF shop, the PM emission limit is 0.03 gr/dscf, and it only applies during periods of primary oxygen blow. The primary oxygen blow is the period in which oxygen is initially blown into the furnace and does not include any subsequent reblows. For BOPF with open hood systems, the PM emission limits are 0.02 gr/dscf for an existing BOPF shop and 0.01 gr/dscf for a new BOPF shop. These emission limits apply during all periods of the steel production cycle. The steel production cycle begins when the furnace is first charged with scrap and ends 3 minutes after slag is removed. The BOPF limits are a flow-weighted average when multiple control devices are operated in parallel. The PM emission limits for a control device applied solely to secondary emissions from a BOPF are 0.01 gr/dscf for an existing BOPF shop and 0.0052 gr/dscf for a new BOPF shop. Secondary emissions are those not controlled by the primary emission control system, including emissions that escape from open and closed hoods and openings in the ductwork to the primary control system. For the BOPF shop, the PM emission limit for a control device applied to emissions from ancillary operations (hot metal transfer, skimming, and desulfurization) is 0.01 gr/dscf for an existing BOPF shop and 0.003 for a new BOPF shop. The PM emission limits for ladle metallurgy operations are 0.01 gr/dscf for an existing BOPF shop and 0.004 gr/dscf for a new BOPF shop. For the BOPF roof monitor, a 20 percent opacity limit applies to fugitive emissions from the BOPF or BOPF shop operations in an existing BOPF shop. This opacity limit is based on 3-minute averages. For a new BOPF shop housing a bottom-blown furnace, a 10 percent opacity limit applies (6-minute average) except that one 6-minute period not to exceed 20 percent may occur once during each steel production cycle. For a new BOPF shop housing a top-blown furnace, a 10 percent opacity limit applies (3-minute average) except that one 3-minute period greater than 10 percent but less than 20 percent may occur once during each steel production cycle.

VOC Emission Control Options

No controls which specifically targeted VOCs were identified for iron and steel plants. Since there is a NESHAP for iron and steel plants, controls for HAPs (which would also control many VOC emissions) should be sufficient to control VOC emissions from iron and steel plants. Four emission units at ISG-Burns Harbor in Indiana are already controlled for VOC. Two of these units are controlled with simple process enclosures, one with a venturi scrubber and one with a direct flame afterburner. The direct flame afterburner controls stack emissions from the BOF refining cycle, while the venturi scrubber controls emissions from the BOF charging, tapping and slagoff processes. The process enclosures control emissions from the sheet temper mill and the rolling process. Since the VOC emissions should be largely controlled under the NESHAP standards, MACTEC did not develop cost analyses for VOC controls. Total VOC emissions from all LADCO iron and steel plant emission units evaluated for BART are approximately 1000 tons. One third of these emissions are from sinter windbox operations.

The final NESHAP rule requires sinter plants to maintain the oil content of the feedstock at or below 0.02 percent. This limit is based on a 30-day rolling average. There is also an alternative VOC limit of 0.2 pound of VOC per ton (lb/ton) of sinter produced. This limit is also based on a 30-day rolling average. Thus VOC emissions from sintering operations (the largest sources of VOC emissions for LADCO BART facilities) should be controlled as long as the plant is considered “major” for HAPS.

SECTION 3
IRON AND STEEL PLANT BART ENGINEERING SCREENING ANALYSIS

Application of BART Screening to Model Iron and Steel Plant Sources

The first four of the five BART evaluation steps are completed in this section on a model iron and steel plant screening level. The fifth step, selecting BART for the iron and steel plant emission units identified above, takes into account as much source-specific data as possible with respect to control options, costs and any non-air environmental impacts identified for those sources. The analysis of potential BART control technologies must take into account:

- The available retrofit control options,
- Any pollution control equipment in use at the source,
- The costs of compliance with control options,
- The remaining useful life of the facility, and
- The energy and non-air quality environmental impacts of control options.

The BART screening study uses a model iron and steel facility approach, which attempts to represent average operational conditions for an iron and steel plant across the various sources identified in the list of emission units for LADCO. Each iron and steel plant is different, and site-specific issues must be considered in the BART analysis. Site-specific conditions are discussed at the end of this section.

Information Sources

The screening BART analysis used the following primary information sources. Cost information was developed from the following sources:

- Emission control costs are estimated using the capital costs identified in the MACTEC spreadsheet identifying the top three control technologies for each pollutant. A list of references/sources reviewed to develop that list was provided with the spreadsheet. Operating costs were based on the EPA Air Pollution Control Cost Manual.
- Control equipment costs were also obtained from readily available vendor information.
- All control costs were adjusted for inflation using the Consumer Price Index to provide constant dollar estimates.
- Information gaps were addressed by collecting additional cost data from control equipment manufacturers or trade organization (e.g. ICAC).
- Gas and electric costs are based on the U.S. Department of Energy's data for industrial sources (http://www.eia.doe.gov).
- Wastewater treatment costs are obtained from the EPA Air Pollution Control Cost Manual.

In addition to these control cost information sources, MACTEC also used information from vendors, trade associations and the EPA documents "Alternative Control Techniques Document – NO_x Emissions From Iron And Steel Mills," EPA Report # EPA-453/R-94-065, 1994 and "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants - Background Information for Proposed Standards", EPA Report # EPA-453/R-01-005, January 2001 to assist in developing the parameters for the model iron and steel plant. The NESHAP report was particularly useful because one of the primary plants considered in that report was the former Bethlehem Steel plant at Burns Harbor, IN (now ISG-Burns Harbor).

General Control Technology Review Issues

This section outlines important issues that must be taken into account when performing a case-by-case BART evaluation.

Emission Controls vs. Impact on Visibility

In accordance with 40 CFR 51.308(e)(1)(ii)(A) and (B), a BART determination must be based on the following two analyses:

> "*(A) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source …; and*
> *(B) An analysis of the degree of visibility improvement that would be achieved in each mandatory Class I Federal area as a result of the emission reductions achievable from all sources subject to BART located within the region that contributes to visibility impairment in the Class I area, based on the analysis conducted under paragraph (e)(1)(ii)(A) of this section."*

This work is focused strictly on item A, the best system of continuous emission control technology and the associated emission reductions (i.e., the BART engineering analysis). For this analysis, a series of spreadsheets were developed to calculate the costs associated with the various control options evaluated for each model source. The spreadsheets were made flexible enough to handle some source-specific input, enabling the user to recalculate costs using these more source-specific inputs. For this analysis, the emission control costs reported in this section for the model sources include estimates of capital costs, operating costs and cost effectiveness (in units of dollars per ton of pollutant removed). It is important to remember that each pollutant has a different impact on visibility.

As indicated earlier, the majority of SO_2 and NO_x emissions from iron and steel plants are associated with fuel fired operations such as process heaters and boilers along with coke underfiring and sinter (windbox) production. In addition, these sources were substantial contributors to PM emissions. According to the information provided by LADCO, the primary fuels used for process heaters and boilers are natural gas, coke oven gas or blast furnace gas. The spreadsheets prepared were developed assuming that coke oven gas and blast furnace gas were the primary fuels. While coke oven gas and blast furnace gas are similar to natural gas, the SO_2 emissions from these types of emission units required that the SO_2 emission factor for natural gas be raised to account for the higher sulfur levels found in coke oven and blast furnace gases relative to natural gas. The emission factor was raised enough to roughly approximate the mean SO_2 emissions found for all coke oven or blast furnace gas operations at the LADCO iron and steel facilities. Because the average emissions of SO_2 from natural gas fired boilers and process heaters was approximately 10 tons per year, we did not develop cost estimates for natural gas fired units for SO_2. For NO_x, we used a single emission factor (natural gas) to approximate all three gases since natural gas process heaters and boilers generally have higher NO_x emissions than either blast furnace or coke oven gas. We did not perform cost analyses for any secondary fuel types since their emissions were very small.

We also evaluated PM only sources and more simplified cost estimation procedures (e.g., for enclosures) were developed to assess the control costs and emission reductions for these sources.

Site-specific Factors that Affect Control Costs

Although the model sources have been developed to provide a general indication of the technical and economic feasibility of each control technology, a unit-specific BART evaluation must still be performed. A case-by-case evaluation should consider these steps.

- Determine the technical feasibility of listed control equipment for each source subject to BART. Check the technical feasibility analysis to see if analysis is consistent with site-specific conditions. Eliminate all technologies that are infeasible.
- Conduct a control cost analysis on the remaining technologies per the listed control technology rankings. At some point it is likely that site-specific vendor quotes will be required to get accurate cost analysis results. However, one of the reasons we decided to use the model source approach was that if there are a significant number of similar sources, selection of a typical-sized source helps minimize the amount of work needed to perform the cost analysis. Use of the appropriate model source cost analysis in this report as guidance for the cost analysis should provide a relatively good approximation of the potential costs. In addition, most of the cost analyses tools that are available (such as the EPA Control Cost Manual) are generally only good to within about 30 percent. While we have tried to include some specific items that are site-specific, a further review of the list of factors that affect site-specific retrofit costs is advised. From that review, one should identify those factors for which costs will affect control equipment installation at the specific site and include them in the cost analysis. For example, the utility costs used in the spreadsheets should be checked and any appropriate adjustments in the cost calculations made.
- Compare the calculated control costs to the results of the economic affordability analysis to determine which controls are economically feasible and select the appropriate controls as BART. Conduct a site-specific economic analysis of control cost affordability. Site-specific factors can significantly impact the installed costs of pollution control equipment. This is especially true at retrofits of existing equipment, which is the case with BART-eligible sources. Site-specific factors that can impact control costs include:
    - Site preparation work due to removal of existing equipment or modification of existing buildings and structures.
    - Site access for equipment delivery and erection. Existing buildings and structures may limit access to the construction site by cranes and other construction equipment.
    - Additional engineering costs to address piping and duct work tie-ins to existing equipment and structural issues caused by installing new equipment that was not planned for in the original equipment design. Process Safety Management Hazardous Operation (Haz-Op) review requirements and resultant safety system designs could also add to engineering costs.
    - Additional piping and insulation costs to fit new piping and ductwork within existing pipe racks and equipment support structures.
    - Auxiliary equipment that may be needed to accommodate the new control system e.g. blowers, heat exchangers, duct burners, or bypass stacks.
    - Lost production due to process equipment down time while the new equipment is being installed. This generally occurs when piping and duct work are tied in to existing equipment.
- If the facility is located in a relatively remote location, freight costs may be higher than standard estimating factors.
- For larger facilities, installation of control equipment will likely require on-site fabrication, which can increase construction costs.

- Site-specific wastewater treatment costs should be carefully evaluated. The raw materials used in production affect the type of constituents that may be found in wastewater streams. When certain materials are captured by wet scrubbing systems, they will likely affect wastewater quality, and the impact of scrubber blowdown on wastewater management systems should be considered. Compliance with water quality standards also needs to be considered.

Model Source Parameters

The BART screening evaluation uses a model iron and steel plant source to develop cost estimates for pollution control equipment. The model iron and steel plant parameters are listed in Table 3.1. The model source parameters were selected by using information collected as part of the following documents:

1. "Assessment of Control Options For Bart-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants, And Paper and Pulp Facilities," Draft Document prepared for NESCAUM, December 2004.
2. "Alternative Control Techniques Document – NO_x Emissions From Iron And Steel Mills," EPA Report # EPA-453/R-94-065, 1994
3. "National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants - Background Information for Proposed Standards", EPA Report # EPA-453/R-01-005, January 2001

In addition, information from internet websites related to iron and steel production and actual plant specific data provided by IN for the ISG-Burns Harbor facility were utilized for supplemental information.

Although three fuel types are used for fuel fired equipment at the LADCO iron and steel plants (natural gas, coke oven gas and blast furnace gas), MACTEC used only one gas to produce the cost estimates (and emission reductions). We used a "process gas" that roughly reflected the composite composition of coke oven gas and blast furnace gas, since they were the two predominant gases used as fuel at the LADCO iron and steel plants. The parameters used to estimate costs for typical operations at iron and steel plants are provided in Table 3.1 below.

TABLE 3.1 SUMMARY OF MODEL IRON AND STEEL PLANT OPERATING CHARACTERISTICS.

Emission Unit Type	Flow	Exit Temperature (ºF)
Boilers	264,000	450
Coke underfire	115,000	490
Furnaces	109,000	1200
Sinter windbox	623,100	114

Model Iron and Steel Plant NO_x Control Technology Review

Thermal NO_x from fuel combustion in boilers, furnaces, process heaters, coke underfiring, and sinter production are the primary source of emissions from iron and steel plants. The five steps used to determine BART for the model iron and steel plant are examined below.

1. Identify Available Retrofit Control Technologies
2. Eliminate Technically Infeasible Options
3. Rank Remaining Control Technologies

4. Evaluate Impacts and Document the Results
5. Recommend BART for model source

BART Step 1: Identify All Available Retrofit Control Technologies

The control technologies identified for NO_x are as follows:

- Low-NO_x Burners (LNB)
- Low NO_x burners with FGR (LNB/FGR)
- Low NO_x burners with Selective Non-catalytic Reduction (SNCR)
- Ultra-low NO_x burners (ULNB)
- Ultra-low NO_x burners (ULNB) with Selective Catalytic Reduction (SCR)
- Selective Catalytic Reduction (SCR)

The previous section provided background information on these control technologies.

BART Step 2: Eliminate Technically Infeasible Options

A summary of the technical feasibility analysis is listed in Table 3.2. Details of the analysis for each control technology follow the summary table.

TABLE 3.2 SUMMARY OF TECHNICAL FEASIBILITY FOR IRON AND STEEL PLANT NO_X EMISSIONS

Control Technology Feasibility Determination - Issues That Affect Control Technology Feasibility	
Control Type	**Issues**
Flue Gas Recirculation (FGR)	Minimum temperature requirements Minimum oxygen levels Fan capacity Furnace pressure Burner pressure drop Turndown stability
Low-NO_x Burners	Minimum temperature requirements Minimum oxygen levels Flame length
Ultra-Low-NO_x Burners (ULNB)	Minimum temperature requirements Minimum oxygen levels Flame length
Selective Non-Catalytic Reduction (SNCR)	High temperature requirements Ammonium sulfate formation Ammonia water/waste issues Ammonia slip potential
Selective Catalytic Reduction (SCR)	Limited temperature range for operations Ammonium sulfate formation/fouling Ammonia slip potential

FGR – Infeasible when used by itself

From a strictly technical standpoint, FGR is feasible as long as there is no minimum operational temperature/oxygen requirement for the fuel fired emission unit. FGR may also affect fan capacity, furnace pressure, burner pressure drop, and turndown stability. If these are critical parameters for processes associated with iron and steel production, then FGR may be infeasible. However for this study, we consider FGR by itself to be infeasible because of its generally low control efficiency when used alone. It is considered feasible when used in conjunction with LNB.

Low-NO_x Burners and Low NO_x Burners with FGR – Feasible

LNB are currently in use at some iron and steel facilities so LNB is considered feasible for use at most fuel fired processes within an iron and steel plant. It is even more efficient when coupled with FGR for processes that can tolerate the reduce pressures and other slight operational changes that LNB/FGR cause for fuel fired emission units.

Low-NO_x Burners with SNCR – Potentially infeasible depending upon temperature and sulfur content

There are currently no LNB/SNCR controls active or planned for iron an steel plants. Since LNB is in current use there should be no reason that LNB couldn't be used for iron and steel fuel fired emission units coupled with SNCR. However, the SNCR reagents must be injected into the furnace at 1,600 °F to 2100 °F. Thus if combustion zone temperatures within the fuel fired emission unit do not fall into this range, then adding SNCR to LNB would be infeasible. Many of the fuel fired processes at iron and steel plants have firing temperatures in this range. Additionally, SNCR tends to be less efficient at low NO_x concentrations. Typical values are 200–400 ppm and SNCR operates more efficiently at the middle to upper end of this range. A second issue with SNCR is the potential for formation of ammonium sulfate salts. If sulfur oxides are present in the gas stream they can react with excess ammonia from the SNCR process to form ammonium salts. These materials are very sticky and cause plugging problems if the gas drops below the adiabatic saturation temperature of 350° F. Thus downstream cleaning may be required. Since coke oven gas and blast furnace gas are higher in sulfur than natural gas (but still likely lower than oil or coal), there may not be an issue with SNCR and ammonium sulfate salts. However since there are no active installations of SNCR either alone or in combination with LNB at iron and steel plants, it cannot be completely ruled out. Ammonia also poses potential water quality issues. Ammonia slip released to the atmosphere could contaminate surface waters by deposition. Ammonia may also absorb onto fly ash in some boilers leading to potential issues related to disposal or reuse of the ash. While we have assumed for costing purposes that the model iron and steel fuel fired combustion units have temperatures sufficient for use of this technology, the temperature characteristics of each specific boiler need to be verified in order to definitively say that this technology will work for industrial boilers. We have also assumed (for costing purposes) that sulfate salts won't be a problem but further information would be needed to provide a complete assessment.

Ultra-low NO_x Burners – Feasible

ULNB have similar constraints to FGR. Low-NO_x and ULNB reduce NO_x formation by restricting flame temperature under low oxygen levels. As long as there are no constraints within the facility for flame temperature and/or oxygen levels for the fuel fired emission unit, ULNB should be feasible. In addition, ULNB typically has a longer flame pattern than a standard burner. The impact of longer flames should be evaluated when considering installation of these burners.

Ultra-low NO_x Burners/SCR – Feasible with the correct temperature

The SCR catalysts generally work only in an operating temperature range of 480 °F to 800 °F but will tolerate fairly large swings within that range. Above 850 °F, NH_3 is oxidized. In general, the SCR catalysts may be fouled or deactivated by particulates present in the flue gas. In addition, for iron and steel plants, the presence of alkalies and lime (limestone is used in the sintering process) as well as sulfur dioxide in the exhaust gases is also of concern. These potential fouling problems generally require that the SCR system be installed after the particulate collection device. Recent developments have led to sulfur tolerant SCR catalysts which limit SO_2 oxidation to less than 1 percent. Soot blowers are commonly used to prevent dust accumulation on SCR catalysts.

Since there are current SCR-only removal systems for some types of iron and steel fuel fired emission units, the use of SCR in conjunction with ULNB should be feasible.

SCR – Feasible with the correct temperature

All of the same conditions related to the coupled ULNB/SCR control apply to SCR but since there are current SCR only removal systems for some types of iron and steel fuel fired emission units, the use of SCR is considered technically feasible.

BART Step 3: Rank Remaining Control Technologies

The control technologies evaluated and their control efficiencies are presented in Table 3.3. Control efficiencies for the six controls/control pairs identified as feasible are presented.

TABLE 3.3 CONTROL TECHNOLOGY RANKINGS FOR IRON AND STEEL PLANT FUEL FIRED EMISSION UNITS GENERATING NO_X - CONTROL EFFICIENCY (TYPICAL CONFIGURATIONS LISTED)

Control Technology	Control Efficiency (%)
LNB	40
LNB + FGR	50-72
LNB + SNCR	50-89
ULNB	75-85
SCR	70-90
ULNB + SCR	85-97

BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for each of the technically feasible control technologies is detailed below. The control cost calculation sheets for NO_x are located in Attachment A.

Economic impacts.

This section provides the costs for implementing each of the control technologies that were found to be feasible that are listed in Table 3.3 above. Costs estimated are based on the model iron and steel plant parameters listed above.

The cost for installation of FGR is assumed to be relatively low compared to technologies such as SCR and SNCR. The majority of costs are associated with the ducting and piping, fans and blowers that may be necessary for recirculation of the flue gas. However, FGR is not normally instituted by itself, but in conjunction with LNBs. The cost for installation of new burners is also assumed to be relatively low compared to SNCR and SCR. Thus LNB, LNB with FGR and ULNB options (without additional controls like SCR or SNCR) are likely to be relatively low. Low-NO_x and ULNB burners typically have longer flame patterns than standard burners. The impact of longer flames should be evaluated when considering the cost of installation for these burners.

Like FGR, LNBs are not usually installed by themselves (at least not to achieve BACT or BART levels of controls – they may be installed by themselves to meet other emission limit standards). Our cost estimates were prepared for LNB with FGR and SNCR. Those costs assume a minor amount of work on the fuel fired emission unit and piping revisions will be needed.

The hardware for a SNCR system includes the urea handling system including a vaporizer, storage tank, blower or compressor, and various valves, indicators, and controls; the injectors; transition ductwork; and a continuous emissions monitoring system. Potential site-specific costs not included but that may be necessary are additional particulate removal equipment and ductwork for a control equipment bypass. As mentioned in the technical feasibility step of the evaluation, if the temperature range is not met by the fuel fired emission unit, modifications would be required to increase the gas temperature so that the required reaction temperatures were met. In general waste gas stream reheating is not performed with SNCR since the combustion chamber acts as the reaction chamber. Thus, our costs do not include estimates for reheating the waste gas stream to meet the required temperature levels for the SNCR to operate. This technology is only applicable where the temperatures of the fossil fuel fired emission unit are already adequate for use of this control technology. Additional costs may be necessary for cleaning due to fouling of duct lines if sulfates are available. Each facility will have to determine if this option is feasible on a site-specific basis.

The hardware for a SCR system includes catalyst materials; the ammonia system including a vaporizer, storage tank, blower or compressor, and various valves, indicators, and controls; the ammonia injection grid; the SCR reactor housing (containing layers of catalyst); transition ductwork; and a continuous emissions monitoring system. Costs may vary nominally if aqua ammonia or urea is used instead of anhydrous ammonia. Potential site-specific costs not included but that may be necessary are additional particulate removal equipment and ductwork for a control equipment bypass. If mechanical cleaners are not present, additional gas cleaning may be needed for SCR. Some gas cleaning typically occurs at iron and steel plants. Fuel fired emission units often have bypasses on SCR systems to protect them during startup, shutdown, and malfunction conditions, which could damage the SCR catalyst. As mentioned in the technical feasibility step of the evaluation, if the temperature range is not met by the fuel fired emission unit, modifications would be required to either reduce (for units with temperatures higher than the required catalysts) or increase the boiler gas temperature. Our costs do not include estimates for reheating or providing make up air at lower temperatures to meet the required temperature levels for the SCR to operate. In the case where more heat was required to reach the catalyst temperatures, an actual design would most likely include a duct burner to re-heat the gas stream and a heat exchanger for heat recovery. In this case gas re-heat is required because the exhaust gas is too cool for SCR operating temperature. In addition to a heat exchanger, this option could incur significant costs for duct work and larger air blowers. The potential for fouling the exchanger from dust should also be evaluated. Each facility will have to determine if this option is feasible on a site-specific basis.

The costs presented below are based on the high and low ranges of costs that we found in our literature/vendor review. Wherever possible a high and low cost estimate is presented. In addition, the calculated emission reductions are estimated for each control type/pair based on the high and low ranges found in the literature for these technologies (and the coupled technologies that they are frequently used with, e.g., FGR, SNCR, SCR).

Boilers

The low NO_x burner cost and emission reduction calculations show a reduction of 281 tons from an uncontrolled level of 703. Capital costs range from $543K to $6.94 million, with annual costs between $221K to $1.1 million. Cost per ton of pollutant are between $786 to $3,841. For LNB plus FGR, capital costs are between $891K to $7.8 million, with annual costs between $496K to $1.4 million. Between 352 and 506 tons of pollutant are removed from an uncontrolled level of 703 tons. Cost per ton ranges from $981 to $3,994.

When LNB is coupled with SNCR, the capital cost estimates are between $1.8 to $11.7 million with annual operating costs estimated to be between $976K to $2.3 million. Emission reductions are between 352-626 tons from an uncontrolled level of 703 tons. Cost effectiveness values are between $1,560-6,565 per ton.

ULNB capital costs were estimated to be $2.1 million with annual operating costs of $448K. Pollutant removal was estimated between 528 and 598 tons from an uncontrolled rate of 703 tons. Cost effectiveness estimates were between $750 and $850 per ton.

SCR capital costs ranged from $2-16.8 million. Annual operating costs were estimated between $1.5-3.5 million. Pollutant removal rates were between 492 and 633 tons from an uncontrolled level of 703 tons. Cost effectiveness estimates ranged from $2,444-7,176 per ton. When SCR was coupled with ULNB, the capital costs were between $4-19 million with annual costs of approximately $2-4 million. Removal rates were 598-682 tons per year from uncontrolled levels. Cost effectiveness values ranged from $2,925-6,660.

A summary of all costs for NO_x controls on boilers at iron and steel plants is provided in Table 3.4.

TABLE 3.4 – SUMMARY OF COST ESTIMATES FOR NO_X CONTROLS FOR BOILERS AT IRON AND STEEL PLANTS.

Gas Fired Boiler	**LNB**	
Uncontrolled emissions (tpy)	Removal Efficiency	40%
703	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$543,518	$6,938,915
Total Annual Costs	$221,120	$1,080,616
Pollutants Removed (tons/yr)	281	281
Cost per ton pollutant removed	$786	$3,841

Gas Fired Boiler	**LNB + FGR**			
Uncontrolled emissions (tpy)	**Removal Efficiency**	**50%**	**Removal Efficiency**	**72%**
703	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$891,119	$7,810,294	$891,119	$7,810,294
Total Annual Costs	$498,698	$1,428,586	$498,698	$1,428,586
Pollutants Removed (tons/yr)	352	352	506	506
Cost per ton pollutant removed	$1,418	$4,062	$985	$2,821

Gas Fired Boilers	**LNB + SNCR**			
Uncontrolled Emissions (tpy)	**Removal Efficiency**	**50%**	**Removal Efficiency**	**89%**
703	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$1,857,700	$11,772,867	$1,857,700	$11,772,867
Total Annual Costs	$976,279	$2,308,808	$976,279	$2,308,808
Pollutants Removed (tons/yr)	352	352	626	626
Cost per ton pollutant removed	$2,776	$6,565	$1,560	$3,688

TABLE 3.4 – SUMMARY OF COST ESTIMATES FOR NO_X CONTROLS FOR BOILERS AT IRON AND STEEL PLANTS (CONTINUED)

Gas Fired Boiler	ULNB	
Uncontrolled emissions (tpy)	Efficiency	Efficiency
703	75%	85%
Total Capital Investment (TCI)	$2,144,309	$2,144,309
Total Annual Costs	$448,261	$448,261
Pollutants Removed (tons/yr)	528	598
Cost per ton pollutant removed	$850	$750

Gas Fired Boiler	SCR			
Uncontrolled emissions (tpy)	Efficiency	70%	Efficiency	90%
703	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$2,015,650	$16,796,000	$2,015,650	$16,796,000
Total Annual Costs	$1,547,054	$3,533,429	$1,547,054	$3,533,429
Pollutants Removed (tons/yr)	492	492	633	633
Cost per ton pollutant removed	$3,142	$7,176	$2,444	$5,582

Gas Fired Boiler	ULNB + SCR			
Uncontrolled emissions (tpy)	Removal Efficiency	85%	Removal Efficiency	97%
703	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$4,159,959	$18,940,309	$4,159,959	$18,940,309
Total Annual Costs	$1,995,316	$3,981,690	$1,995,316	$3,981,690
Pollutants Removed (tons/yr)	598	598	682	682
Cost per ton pollutant removed	$3,337	$6,660	$2,925	$5,836

Furnaces

In general, costs for furnaces are slightly lower than for boilers due to differences in the heat input and flow rates for boilers and furnaces at iron and steel plants. For LNB, the capital costs for furnaces range from $112K to $1.4 million with annual operating costs of $163-$340K. Emission reductions for furnaces are lower than for boilers due to lower uncontrolled emissions of 145 tons. Emission reductions for LNB for furnaces were 58 tons per year with cost effectiveness values between $2,813-5,867 per ton. When LNB is coupled with FGR, the capital costs range from $446K to $2 million with annual operating costs between $438-666K. Emission reductions are between 73-104 tons from uncontrolled levels. Coste effectiveness is between $4,205-9,186 per ton.

LNB coupled with SCR has capital costs between $382K and $2.4 million. Operating costs range from $486-760K. Emission reductions are 73-129 tons against uncontrolled levels of 145 tons. Cost effectiveness values are $3,766-10,493 per ton.

ULNB capital costs are estimated at $442K with operating cost of $219K. Emission reductions are between 109-123 tons per year resulting in cost effectiveness values of $1,782-2,018 per ton.

SCR capital costs were between $415K-$3.4 million. Annual cost estimates were $987K-$1.4 million. Emission of NOx were reduced between 102-131 tons resulting in cost effectiveness values of $7,566-$13,762 per ton.

Finally ULNB coupled with SCR resulted in capital costs of $857K-$4 million and annual costs between $1.2-1.6 million. Emissions were reduced between 123-141 tons. Cost effectiveness values were between $8,581-13,114 per ton.

A summary of all costs for each control evaluated for furnaces at iron and steel plants is provided in Table 3.5.

TABLE 3.5 – SUMMARY OF COST ESTIMATES FOR NO_X CONTROLS FOR FURNACES AT IRON AND STEEL PLANTS.

Gas Fired Furnace	LNB	
Uncontrolled emissions (tpy)	Removal Efficiency	40%
145	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$112,048	$1,430,484
Total Annual Costs	$163,134	$340,322
Pollutants Removed (tons/yr)	58	58
Cost per ton pollutant removed	$2,813	$5,867

Gas Fired Furnace	LNB + FGR			
Uncontrolled emissions (tpy)	Removal Efficiency	50%	Removal Efficiency	72%
145	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$446,659	$2,136,025	$446,659	$2,136,025
Total Annual Costs	$438,966	$666,004	$438,966	$666,004
Pollutants Removed (tons/yr)	73	73	104	104
Cost per ton pollutant removed	$6,055	$9,186	$4,205	$6,379

Gas Fired Furnace	LNB + SNCR			
Uncontrolled emissions (tpy)	Removal Efficiency	50%	Removal Efficiency	89%
145	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$382,972	$2,427,022	$382,972	$2,427,022
Total Annual Costs	$486,064	$760,770	$486,064	$760,770
Pollutants Removed (tons/yr)	73	73	129	129
Cost per ton pollutant removed	$6,704	$10,493	$3,766	$5,895

Gas Fired Furnace	ULNB	
Uncontrolled emissions (tpy)	Efficiency	Efficiency
145	75%	85%
Total Capital Investment (TCI)	$442,057	$442,057
Total Annual Costs	$219,491	$219,491
Pollutants Removed (tons/yr)	109	123
Cost per ton pollutant removed	$2,018	$1,781

TABLE 3.5 – SUMMARY OF COST ESTIMATES FOR NO_X CONTROLS FOR FURNACES AT IRON AND STEEL PLANTS (CONTINUED)

Gas Fired Furnace	SCR			
Uncontrolled emissions (tpy)	Efficiency	70%	Efficiency	90%
145	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$415,534	$3,462,560	$415,534	$3,462,560
Total Annual Costs	$987,408	$1,396,907	$987,408	$1,396,907
Pollutants Removed (tons/yr)	102	102	131	131
Cost per ton pollutant removed	$9,728	$13,762	$7,566	$10,704

Gas Fired Furnace	ULNB + SCR			
Uncontrolled emissions (tpy)	Removal Efficiency	85%	Removal Efficiency	97%
145	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$857,591	$3,904,617	$857,591	$3,904,617
Total Annual Costs	$1,206,899	$1,616,397	$1,206,899	$1,616,397
Pollutants Removed (tons/yr)	123	123	141	141
Cost per ton pollutant removed	$9,792	$13,114	$8,581	$11,492

Environmental impacts

Because LNB, LNB and FGR and ULNB are simply a change in the combustion character of the burner, there are no known adverse environmental impacts associated with this technology.

Undesirable reactions can occur in either an SCR or SNCR process, including the oxidation of NH_3 and SO_2 to form sulfate salts. These compounds are corrosive and can be deposited on the exhaust duct walls. In addition, ammonium sulfate and ammonium bisulfate condense at temperatures below 400 °F, forming white solids, which will increase particulate emissions if exit temperatures reach this point after passing any particulate devices. Ammonia slip, or un-reacted ammonia, is also a problem with these technologies. Ammonia concentrations in the exhaust gas are typically in the 5-ppm to 10-ppm range. Ammonia can react with sulfur and nitrogen oxides to form fine particulate matter that contributes to haze (exactly what BART is trying to reduce). In addition, storage of anhydrous ammonia can pose some environmental and safety risks associated with the potential for an accidental release. Aqua ammonia and urea may be substituted for ammonia; but these systems have higher capital and operating costs than anhydrous ammonia. Ammonia also poses potential water quality issues. Ammonia slip released to the atmosphere could contaminate surface waters by deposition.

Energy impacts

In FGR systems, since the flame efficiency is affected, the boiler may be less energy efficient than standard burners which could result in a nominal increase in fuel consumption. Some information in the literature suggests that since ULNB are generally a form of FGR, they also may be less efficient than standard burners. However, vendors claim that the new ULNB (and LNB) designs do not lower the boilers fuel efficiency. Thus, a nominal increase in fuel consumption for ULNB may occur.

With respect to SNCR, there may be some minor costs for extra energy for downstream cleaning processes which may be required. Otherwise, energy impacts for SNCR are considered minor.

For SCR, additional natural gas may be required if a duct burner is needed to maintain proper catalyst bed temperatures or additional electrical power to run fans and blowers (either for the added temperatures needed or in the case of cooling of the waste stream).

SO_2 Control Technology Review

The majority of SO_2 emissions at the LADCO BART emission units identified for this study at iron and steel plants come from sintering, coke oven underfiring, furnaces and boilers. This section discusses each step in the BART engineering analysis process for SO_2 controls for these sources.

BART Step 1: Identify Available Retrofit Control Technologies

The top control technologies identified earlier for SO_2 are as follows:

- Advanced flue gas desulfurization
- Wet flue gas desulfurization
- Dry absorption (dry FGD)

Additional information on each of these control technologies was found in Section 2.

BART Step 2: Eliminate Technically Infeasible Options

All of the control technologies identified in step 1 are deemed technically feasible. With that said, MACTEC was not able to identify any current SO_2 controls at iron and steel plants. Thus for the cost analyses, MACTEC considered all controls as feasible.

Fuel switching as an SO_2 control is generally not an option for iron and steel plant sources since they typically are already firing gaseous fuels (e.g., blast furnace gas, coke oven gas, or natural gas). A change to a different fuel could potentially increase the sulfur content of the fuel, even though blast furnace gas and coke oven gas are relatively high in sulfur compared to natural gas.

BART Step 3: Rank Remaining Control Technologies

The technically feasible control technologies and their control efficiencies are presented in Table 3.6.

TABLE 3.6 CONTROL TECHNOLOGY RANKINGS FOR IRON AND STEEL PLANT SO_2 CONTROL.

Control Technology	Control Efficiency (%)
AFGD	95-99.5
Wet FGD	90-99
Dry FGD (Spray Dryer Absorption)	90-95

BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for the technically feasible control technologies is detailed below. A summary of the impacts and the control cost calculation sheets are located in Attachment A.

Economic impacts

For the wet scrubber, the control cost calculations were prepared using lime as the base in the scrubbing liquor. Caustic (NaOH) and limestone are potential alternatives for a scrubber. While lime and limestone require additional equipment for slurry preparation and for solids separation from the sludge generated in the scrubber, lime scrubbers are the most commonly used since lime is plentiful and relatively cheap.

Materials of construction must also be made suitable for caustic, lime, or limestone if existing equipment is modified for wet scrubbing of SO_2. Although not calculated here, wet FGD systems offer some level of particulate control in addition to controlling SO_2.

AFGD systems require additional capital costs for the spargers and blowers necessary to oxidize the waste product to gypsum and for equipment to dewater the product (e.g., centrifuge). However if the commercial grade gypsum can be sold, some of these costs can be offset.

Dry FGD costs were calculated based on the low and high control efficiencies. For dry scrubbers, the flue gas must be cooled to a temperature 10 to 20 degrees above adiabatic saturation. This is typically accomplished using a heat recovery boiler, an evaporative cooler or a heat exchanger. In addition, if the facility does not have one, a particulate removal device is required for removal of the dry materials used to absorb SO_2.

For all scrubbers, costs for an additional or upgraded induced air draft fan to make up for pressure drops within the system may be required. In addition, for wet systems, flue gas reheating may be required, thus a reheater may be necessary.

In preparing the cost estimates, no emission factors were identified for either blast furnace gas or coke oven gas. We used the SO_2 emissions from the LADCO sources to develop a multiplier for the natural gas emission factor from boilers to use in estimating the costs (based on flow, heat input, etc.). The emission factor developed represents a composite gas that is a mix of blast furnace and coke oven gas since these are the two primary fuels used for the four sources evaluated.

Tables 3.7 through 3.10 provide a summary of the estimated costs for each of the SO_2 control systems evaluated for sinter windbox, coke underfiring, boilers, and furnaces, respectively.

Capital costs for sinter windboxes range from $19.8 to 64 million for AFGD, $6.8 – 102 million for wet FGD and $6.4 – 149 million for dry FGD depending upon the control efficiency and whether low or high capital cost assumptions were used.

Annual operating costs for sinter windbox operations range from $7.3 – 15.5 million for AFGD, $7.4-25 million for wet FGD, and $8.2 – 32 million for dry FGD systems.

Cost effectiveness values for AFGD range from about $4,500-10,000 per ton, $4,500-17,000 per ton for wet FGD, and $5,300-$22,000 per ton for dry FGD depending upon the control efficiency.

Similar capital costs are found for coke underfire batteries with the exception of dry FGD. Dry FGD capital costs for coke underfire batteries are slightly lower than those for sinter operations. Annual operating costs for coke underfire battery SO_2 controls were slightly less than those for sinter operations with the range between $4-23 million, depending upon the technology. Cost effectiveness values ranged from $3,000-$17,000 per ton, depending upon the technology.

Capital costs for gas fired boilers and furnaces ranged between $4-122 and $1.2-29 million, respectively depending upon the technology evaluated. Annual costs for SO_2 controls for boilers were between $5-25 million depending upon the control method. For furnaces, these costs were between $2-19 million, depending upon control method. Cost effectiveness values for boilers ranged from $7,600-45,000 and for furnaces between $19,000-206,000.

The costs for SO_2 controls at emission sources at iron and steel plants are high largely due to the fact that these emission sources fire gaseous fuels rather than oil or coal. While the SO_2 emissions are not inconsequential, they typically are not at the same level as for boilers that fire oil or coal. In addition, the MMBtu/hour values used for these sources were significantly higher than those for coal or oil fired boilers.

TABLE 3.7 – SUMMARY OF COST ESTIMATES FOR SINTER WINDBOXES FOR ALL SO_2 CONTROLS.

Sinter Windbox	AFGD			
Uncontrolled emissions (tpy)	Removal Efficiency	95%	Removal Efficiency	99.5%
1628	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$19,808,100	$64,524,200	$19,808,100	$64,524,200
Total Annual Costs	$7,321,173	$15,476,383	$7,321,173	$15,476,383
Pollutants Removed (tons/yr)	1546	1546	1620	1620
Cost per ton pollutant removed	$4,734	$10,008	$4,520	$9,555

Sinter Windbox	Wet FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
1,628	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$6,856,850	$102,887,200	$6,856,850	$102,887,200
Total Annual Costs	$7,453,964	$24,967,739	$7,453,964	$24,967,739
Pollutants Removed (tons/yr)	1465	1465	1628	1628
Cost per ton pollutant removed	$5,088	$17,042	$4,580	$15,340

Sinter Windbox	Dry FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	95.0%
1,628	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$6,480,950	$149,619,700	$6,480,950	$149,619,700
Total Annual Costs	$8,232,267	$32,279,523	$8,232,267	$32,279,523
Pollutants Removed (tons/yr)	1465	1465	1546	1546
Cost per ton pollutant removed	$5,619	$22,033	$5,323	$20,874

TABLE 3.8 – SUMMARY OF COSTS ESTIMATES FOR COKE OVEN UNDERFIRING FOR ALL SO_2 CONTROLS.

Coke Underfire Battery	AFGD			
Uncontrolled emissions (tpy)	Removal Efficiency	95%	Removal Efficiency	99.5%
1447	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$19,808,100	$64,524,200	$19,808,100	$64,524,200
Total Annual Costs	$5,725,728	$13,880,939	$5,725,728	$13,880,939
Pollutants Removed (tons/yr)	1375	1375	1440	1440
Cost per ton pollutant removed	$4,165	$10,098	$3,977	$9,641

Coke Underfire Battery	Wet FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
1,447	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$6,856,850	$102,887,200	$6,856,850	$102,887,200
Total Annual Costs	$4,421,392	$21,935,167	$4,421,392	$21,935,167
Pollutants Removed (tons/yr)	1302	1302	1447	1447
Cost per ton pollutant removed	$3,395	$16,844	$3,056	$15,161

Coke Underfire Battery	Dry FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	95.0%
1,447	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$3,432,350	$111,512,200	$3,432,350	$111,512,200
Total Annual Costs	$4,005,205	$23,340,235	$4,005,205	$23,340,235
Pollutants Removed (tons/yr)	1302	1302	1375	1375
Cost per ton pollutant removed	$3,076	$17,923	$2,914	$16,980

TABLE 3.9 – SUMMARY OF COSTS ESTIMATES FOR GAS FIRED BOILERS FOR ALL SO_2 CONTROLS.

Gas Fired Boiler	AFGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	95%	Removal Efficiency	99.5%
633	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$19,808,100	$64,524,200	$19,808,100	$64,524,200
Total Annual Costs	$5,701,597	$13,856,808	$5,701,597	$13,856,808
Pollutants Removed (tons/yr)	601	601	630	630
Cost per ton pollutant removed	$9,481	$23,041	$9,052	$21,999

Gas Fired Boiler	Wet FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
633	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$6,856,850	$102,887,200	$6,856,850	$102,887,200
Total Annual Costs	$4,857,371	$22,371,146	$4,857,371	$22,371,146
Pollutants Removed (tons/yr)	570	570	633	633
Cost per ton pollutant removed	$8,526	$39,266	$7,674	$35,343

Gas Fired Boiler	Dry FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	95.0%
633	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$4,326,350	$122,687,200	$4,326,350	$122,687,200
Total Annual Costs	$5,142,561	$25,856,779	$5,142,561	$25,856,779
Pollutants Removed (tons/yr)	570	570	601	601
Cost per ton pollutant removed	$9,026	$45,384	$8,551	$42,995

TABLE 3.10 – SUMMARY OF COSTS ESTIMATES FOR GAS FIRED FURNACES/PROCESS HEATERS FOR ALL SO_2 CONTROLS.

Gas Fired Furnace	AFGD			
Uncontrolled emissions (tpy)	Removal Efficiency	95%	Removal Efficiency	99.5%
104	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$4,083,516	$13,301,912	$4,083,516	$13,301,912
Total Annual Costs	$1,990,875	$3,672,103	$1,990,875	$3,672,103
Pollutants Removed (tons/yr)	99	99	104	104
Cost per ton pollutant removed	$20,073	$37,024	$19,165	$35,349

Gas Fired Furnace	Wet FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
104	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$1,413,566	$21,210,592	$1,413,566	$21,210,592
Total Annual Costs	$15,794,498	$19,405,030	$15,794,498	$19,405,030
Pollutants Removed (tons/yr)	94	94	104	104
Cost per ton pollutant removed	$168,094	$206,519	$151,299	$185,886

Gas Fired Furnace	Dry FGD			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	95.0%
131	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$1,219,346	$29,385,592	$1,219,346	$29,385,592
Total Annual Costs	$3,206,229	$7,982,629	$3,206,229	$7,982,629
Pollutants Removed (tons/yr)	117	117	124	124
Cost per ton pollutant removed	$27,298	$67,964	$25,861	$64,387

Environmental impacts

The primary environmental impact from AFGD is byproduct of gypsum. While gypsum is generated as a byproduct, the intent of the AFGD system is to produce gypsum that is commercial grade that can be sold. The primary environmental impact of wet scrubbers is the generation of wastewater and sludge. Waste from wet scrubbers will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities. These impacts will need to be analyzed on a site-specific basis. If lime or limestone scrubbing is used to produce calcium sulfite sludge, the sludge is water-laden, and it must be stabilized for landfilling. If lime or limestone scrubbing is used to produce calcium sulfate sludge, it is stable and easy to dewater. However, control costs will be higher because additional equipment is required. Scrubber exhaust gases are saturated with water, thus creating a visible plume. Plume visibility may be a local/community concern. Once the exhaust mixes with sufficient air, the moisture droplets evaporate, and the plume is no longer visible.

Disposal of removed material from dry FGD systems is also required and will result in landfill impacts.

Energy impacts

A scrubber operates with a high pressure drop, resulting in a significant amount of electricity required to operate the blower and pump. In addition for some technologies, a flue gas reheater may be required resulting in slightly increased fuel usage.

Iron and Steel Plant Emission Units PM Control Technology Review

The majority of particulate matter emissions from iron and steel plants in the LADCO region emanate from three types of emission units: coke oven underfiring, and furnaces and boilers firing process gases (e.g., coke oven gas or blast furnace gas). Some additional emissions may emanate from other processes such as casting, raw materials handling, etc. however these emissions are typically small. The BART steps for PM control of these types of emission units at iron and steel plants are outlined below.

BART Step 1: Identify Available Retrofit Control Technologies

Identified control technologies available for PM are as follows:

- Dust Cartridge (DC)
- Fabric Filter (Baghouse)
- Dry Electrostatic Precipitator (DESP)
- Wet Electrostatic Precipitator (WESP)

For additional information on these control technologies see Section 2. Each of the steps used in the BART engineering analysis for PM controls on iron and steel plant emission units are discussed below.

BART Step 2: Eliminate Technically Infeasible Options

All PM control technologies identified in step 1 are deemed technically feasible except for dust cartridges. Dust cartridges are not feasible for high temperature (above about 200 F) conditions without using synthetic filter materials. Use of synthetic filter materials in dust cartridges for higher temperature applications is prohibitively expensive given that there are other technologies that are available with similar control efficiencies and lower costs. Thus dust cartridges are likely to be infeasible for PM control for coke underfiring, boilers and furnaces at iron and steel plants.

BART Step 3: Rank Remaining Control Technologies

The third of the five steps in the top-down BART analysis is to rank the remaining control technologies by control effectiveness. The remaining control technologies and their control efficiencies are presented in Table 3.11.

TABLE 3.11 CONTROL TECHNOLOGY RANKINGS FOR IRON AND STEEL PLANT PM CONTROL

Control Technology	Control Efficiency (%)
FF	95-100
DESP	90-100
WESP	90-100

BART Step 4: Evaluate Impacts and Document the Results

A discussion of relevant impacts, including (A) economic, (B) environmental, and (C) energy, for each of the technically feasible control technologies is detailed below. The detailed control cost calculation sheets are located in Appendix A.

Economic impacts

Model source control costs for iron and steel plant PM controls for coke underfiring units are shown in Table 3.12, with costs for gas fired boilers and furnaces shown in Tables 3.13 and 3.14. In general, fabric filters are less expensive in capital costs than DESPs or WESPs, but more expensive for annual operating costs than DESPs.

Capital costs range from $690K-$23 million for coke underfiring, $1.5-53 million for boilers and $654K-22 million for furnaces depending upon the control technology. Annual operating costs are between $336K-5 million for coke underfiring, $687K-12 million for boilers, and $374-6 million for furnaces. Cost effectiveness values range from $2,000-36,000 for coke underfiring, $7,000-150,000 for boilers, and $20,000-200,000 for furnaces. The high cost effectiveness values are largely the result of extremely low particulate emissions from gas fired equipment.

TABLE 3.12 – SUMMARY OF COSTS ESTIMATES FOR PM CONTROLS AT COKE UNDERFIRING UNITS.

Coke Underfire Battery	**Fabric Filter**			
Uncontrolled Emissions (tpy)	**Removal Efficiency**	**95%**	**Removal Efficiency**	**99.99%**
164	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$690,000	$8,625,000	$690,000	$8,625,000
Total Annual Costs	$1,274,748	$2,341,156	$1,274,935	$2,341,342
Pollutants Removed (tons/yr)	156	156	164	164
Cost per ton pollutant removed	$8,192	$15,045	$7,784	$14,295

Coke Underfire Battery	**Wet ESP**			
Uncontrolled Emissions (tpy)	**Removal Efficiency**	**90%**	**Removal Efficiency**	**99.99%**
164	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$2,404,219	$23,355,268	$2,404,219	$23,355,268
Total Annual Costs	$2,281,694	$5,371,921	$2,281,694	$5,371,921
Pollutants Removed (tons/yr)	147	147	164	164
Cost per ton pollutant removed	$15,478	$36,440	$13,931	$32,799

Coke Underfire Battery	**Dry ESP**			
Uncontrolled Emissions (tpy)	**Removal Efficiency**	**90%**	**Removal Efficiency**	**99.99%**
164	**Low Capital Cost**	**High Capital Cost**	**Low Capital Cost**	**High Capital Cost**
Total Capital Investment (TCI)	$1,144,866	$14,883,259	$1,144,866	$14,883,259
Total Annual Costs	$336,640	$2,363,019	$337,014	$2,363,392
Pollutants Removed (tons/yr)	147	147	164	164
Cost per ton pollutant removed	$2,284	$16,029	$2,058	$14,430

TABLE 3.13 - SUMMARY OF COSTS PM CONTROLS FOR GAS FIRED BOILERS.

Gas Fired Boiler	Fabric Filter			
Uncontrolled Emissions (tpy)	Removal Efficiency	95%	Removal Efficiency	99.99%
90	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$1,584,000	$19,800,000	$1,584,000	$19,800,000
Total Annual Costs	$2,628,714	$5,076,815	$2,628,816	$5,076,918
Pollutants Removed (tons/yr)	85	85	90	90
Cost per ton pollutant removed	$30,855	$59,589	$29,316	$56,617

Gas Fired Boiler	Wet ESP			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
90	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$5,519,250	$53,615,571	$5,519,250	$53,615,571
Total Annual Costs	$4,984,855	$12,078,941	$4,984,855	$12,078,941
Pollutants Removed (tons/yr)	81	81	90	90
Cost per ton pollutant removed	$61,761	$149,654	$55,590	$134,702

Gas Fired Boiler	Dry ESP			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
90	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$2,628,214	$34,166,786	$2,628,214	$34,166,786
Total Annual Costs	$687,143	$5,339,003	$687,348	$5,339,207
Pollutants Removed (tons/yr)	81	81	90	90
Cost per ton pollutant removed	$8,513	$66,148	$7,665	$59,542

TABLE 3.14 - SUMMARY OF COSTS PM CONTROLS FOR GAS FIRED FURNACES.

Gas Fired Furnace	Fabric Filter			
Uncontrolled emissions (tpy)	Removal Efficiency	95%	Removal Efficiency	99.99%
18	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$654,000	$8,175,000	$654,000	$8,175,000
Total Annual Costs	$1,942,898	$2,953,667	$1,942,919	$2,953,688
Pollutants Removed (tons/yr)	18	18	18	18
Cost per ton pollutant removed	$110,621	$168,170	$105,101	$159,779

Gas Fired Furnace	Wet ESP			
Uncontrolled Emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
18	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$2,278,781	$22,136,732	$2,278,781	$22,136,732
Total Annual Costs	$3,491,156	$6,420,154	$3,491,156	$6,420,154
Pollutants Removed (tons/yr)	17	17	18	18
Cost per ton pollutant removed	$209,815	$385,846	$188,853	$347,296

Gas Fired Furnace	Dry ESP			
Uncontrolled emissions (tpy)	Removal Efficiency	90%	Removal Efficiency	99.99%
18	Low Capital Cost	High Capital Cost	Low Capital Cost	High Capital Cost
Total Capital Investment (TCI)	$1,085,134	$14,106,741	$1,085,134	$14,106,741
Total Annual Costs	$374,041	$2,294,695	$374,083	$2,294,737
Pollutants Removed (tons/yr)	17	17	18	18
Cost per ton pollutant removed	$22,480	$137,909	$20,236	$124,133

MACTEC did not prepare separate cost estimates for PM controls for other sources at iron and steel plants that can be ducted to existing PM controls, since the majority of emissions for PM are from the three sources that were evaluated. The control cost ranges for PM controls for these sources are sufficiently broad that the likely costs for ducting and extra capacity to handle these emissions would only add minimally to the costs.

PM Fugitive Emission Costs

There are a number of smaller fugitive dust sources or sources that can be controlled using either enclosures or partial enclosures with wet suppression. However, the emissions from these sources for the LADCO facilities were exceptionally small so MACTEC did not develop cost estimates for these sources.

Environmental impacts

For fabric filters, and dry ESPs the main environmental impact is related to disposal of the dry materials collected. The primary environmental impact of wet ESPs is the generation of wastewater and sludge from the washing of the collector. Waste from the scrubber will increase the sulfate and solids loading in the facility's wastewater. This places additional burdens on a facility's wastewater treatment and solid waste management capabilities.

No known environmental impacts are known for the fugitive dust sources.

Energy impacts

Energy requirements (other than the electricity used to power the collector portion of the device) are relatively low. A wet ESP will also require pumps and piping to run the wash water to the ESP.

Iron and Steel Plant VOC Control Technology Review

No specific controls targeting VOC emissions from iron and steel plants were identified. There are currently VOC controls on four emission units at ISG-Burns Harbor in Indiana. Two of these units are controlled with simple process enclosures, one with a venturi scrubber and one with a direct flame afterburner. The direct flame afterburner controls stack emissions from the BOF refining cycle, while the venturi scrubber controls emissions from the BOF charging, tapping and slagoff processes. The process enclosures control emissions from the sheet temper mill and the rolling process. These controls were likely put in place due to the iron and steel NESHAP standards. Since compliance with NESHAP standards basically satisfies the BART requirements, MACTEC did not perform costing for any other VOC controls. Total VOC emissions from all LADCO iron and steel plant emission units evaluated for BART are approximately 1000 tons. One third of these emissions are from sinter windbox operations.

SECTION 4
SOURCE SPECIFIC DATA AND BART RECOMMENDATIONS

This section provides source specific data relative to remaining useful life and existing controls. In addition we provide recommendations for the BART controls on the iron and steel plant emission units identified in the LADCO region.

Remaining Useful Life

MACTEC requested information on remaining useful life of each of the iron and steel plant emission units identified for this BART engineering analysis. We received no information concerning remaining useful life on these units. For the purposes of this analysis, we assumed that the remaining useful life of each emission units was a minimum of at least 10 years and that it was likely that some units would continue to operate for at least 20-30 more years with proper maintenance and upkeep. Thus we found nothing to suggest that the amortization of capital costs or calculation of annual operating costs would be affected by the remaining useful life.

Existing Controls

MACTEC also requested information on any existing controls for the iron and steel plant emission units identified. Table 4.1 shows the information related to current controls. Several of the iron and steel plant emission units already have particulate controls in place, primarily ESPs or fabric filters. No existing controls were identified for either SO_2 or NO_x. No information was provided on the efficiency of these devices.

Fuel Issues

Unlike some other sources, the fuel firing operations at iron and steel plants primarily fire a single fuel, typically some type of gas (e.g., natural, blast furnace or coke oven). Since these fuels are generally low in sulfur (compared to coal or oil), and since NO_x control costs are fairly low for most of these sources, little would be gained from fuel switching. Fuel switching is generally not an option for iron and steel plants.

Table 4.2 shows our preliminary estimates of BART controls for iron and steel plant emission units that may be subject to BART. Our determination of the BART controls selected were based on 1) existing controls, 2) control efficiency levels, 3) costs, and 4) marginal improvements in efficiency. In general we proposed ULNB or LNB for NO_x control primarily because the costs for these controls are significantly lower than other methods and the marginal improvements in control efficiency are generally not as cost effective. Selection of SO_2 controls was significantly more difficult. Estimated costs were high due largely to the MMBtu estimates we developed for the gas fuels. In general we have proposed AFGD or wet FGD for the largest sources. We believe that AFGD is potentially workable for iron and steel plants but there are few AFGD installations on any emission unit other than utility boilers so an alternative may be necessary. However in several cases we have recommended that a source be ducted to a common SO_2 control unit in order to keep costs as low as possible. Determination of the feasibility of this approach requires more source specific information than was available for this study. It may not be practical in all cases.

Finally for most sources we proposed use of existing PM controls (or use of modified existing controls). For those cases where there were no controls we typically recommended either fabric filters or dry ESP since those were most cost effective. That said, there is the very real possibility that existing controls will be all that is required for iron and steel plants if they are subject to the NESHAP requirements. If the final

BART guidelines remain substantially the same as the draft guidelines, NESHAP levels of controls would be considered as satisfying BART. Finally for the sources not easily ducted we recommended partial enclosures, wet suppression or best management practices. PM emissions from these sources are very low and these types of controls represent the most cost effective approach for controlling emissions from these sources. We have not recommended any VOC controls above those already in place for the iron and steel NESHAP.

TABLE 4.1 LADCO BART CATEGORY 4 (IRON AND STEEL PLANT) EMISSION UNITS – EXISTING CONTROLS

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO_2	NO_2	PM	VOC
ILLINOIS	National Steel Corp	0015	SLAB FURNACE #1	None	None	None	None
ILLINOIS	National Steel Corp	0033	BOF - TWO VESSELS	None	None	None	None
ILLINOIS	National Steel Corp	0041	BOILER HOUSE 1: BOILERS 1 TO 7	None	None	None	None
ILLINOIS	National Steel Corp	0042	BOILER HOUSE 1: BOILERS 8 TO 10	None	None	None	None
ILLINOIS	National Steel Corp	0044	BOILER HOUSE 2: BOILER #11 - BLAST FURNACE DEPT	None	None	None	None
ILLINOIS	National Steel Corp	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	None	None	None	None
ILLINOIS	National Steel Corp	0122	SLAB FURNACE #2	None	None	None	None
ILLINOIS	National Steel Corp	0123	SLAB FURNACE #3	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	001	BEDDING PLANT MATL TRANS	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	002	SINTER MIXING DRUM	None	None	Wet Scrubber - Low Efficiency	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	003	SINTER WINDBOX	None	None	Wet Scrubber - High Efficiency	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	004	SINTER MISC MATL HANDLING	None	None	Fabric Filter - Medium Temperature, I.E. 180f<T<250f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	005	SINTER TRANSFER STATIONS	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	006	BLAST FURNACE CAR DUMPER	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	007	BLAST FURNCE THAW SHED	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	008	BF C STOCKHOUSE	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	009	BF D STOCKHOUSE	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	010	BF C CASTHSE, STOVES, FLR	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	011	BF D CASTHSE, STOVES, FLR	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	036	COAL PREPARATION	None	None	Dust Suppression By Chemical Stabilizers Or Wetting Agents	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	037	BATTERY #1 PUSHING	None	None	Wet Scrubber - High Efficiency	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	039	COKE OVEN UNDRFIRE BAT #1	None	None	None	None

TABLE 4.1 LADCO BART CATEGORY 4 (IRON AND STEEL PLANT) EMISSION UNITS – EXISTING CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO_2	NO_2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	040	COKE BATTERY #1 QUENCHING	None	None	Miscellaneous Control Devices	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	041	BATTERY #2 PUSHING	None	None	Fabric Filter - High Temperature, I.E. T>250f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	043	COKE OVEN UNDRFIRE BAT #2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	044	BATTERY #2 QUENCHING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	045	COKE OVEN COAL CHEM PLANT	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	046	COKE SCREENING	None	None	Dust Suppression By Chemical Stabilizers Or Wetting Agents	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	048	CSM #1 PICKLE LINE	None	None	Wet Scrubber - High Efficiency	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	049	CSM #2 PICKLE LINE	None	None	Wet Scrubber - High Efficiency	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	051	COLD SHEET MILL- TANDEM	None	None	Mist Eliminator - Low Velocity, I.E. V<250 Ft/Min	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	052	BATCH ANNEAL FURNACES	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	056	COLD SHEET MILL-DUO MILL	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	057	COLD SHEET TEMPER MILL	None	None	None	Process Enclosed
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	058	COLD SHEET SHIP BLDGS 1&2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	061	CSM EGL LINE CLEANING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	062	CSM EGL LINE PICKLING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	063	CSM EGL LINE ZINC PLATING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	067	NORTH BURNING BED	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	068	SOUTH BURNING BED	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	069	HAND SCARFING BED	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	070	HOT STRIP MILL FURN #1	None	None	None	None

TABLE 4.1 LADCO BART CATEGORY 4 (IRON AND STEEL PLANT) EMISSION UNITS – EXISTING CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	071	HOT STRIP MILL FURN #2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	072	HOT STRIP MILL FURN #3	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	073	HSM ROLLING PROCESS	None	None	Process Enclosed	Process Enclosed
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	076	POWER STATION BOILER #8	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	077	POWER STATION BOILER #9	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	078	POWER STATION BOILER #10	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	079	POWER STATION BOILER #11	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	080	POWER STATION BOILER #12	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	081	#1 ROLL SHOP N. BAGHOUSE	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	082	#1 ROLL SHOP S. BAGHOUSE	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	083	#2 ROLL SHOP BAGHOUSE	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	084	36 SOAKING PITS	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	085	SLAB MILL SCARFER	None	None	Wet Scrubber - Medium Efficiency	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	086	SLAB MILL ROLLING PROCESS	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	088	SLAB YD 3 FURNACE 4&5&6	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	089	SLAB YD 3 SCARFING BED 3	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	091	SLAB YD 3 FLAME CUTTING	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	092	SLAB YD 2 FURNACE 1&2&3	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	093	SLAB YD 2 FLAME CUT BED 2	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	094	SLAB YD 2 SCARFING BED 2	None	None	None	None

TABLE 4.1 LADCO BART CATEGORY 4 (IRON AND STEEL PLANT) EMISSION UNITS – EXISTING CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	095	160"PLATE CONT.FURNACE #1	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	096	160"PLATE CONT FURNACE #2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	097	160"PLATE BATCH FURNCE #4	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	098	160"PLATE BATCH FURNCE #5	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	099	160"PLATE BATCH FURNCE #6	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	100	160"PLATE BATCH FURNCE #7	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	101	160"PLATE BATCH FURNCE #8	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	104	160"PLATE CAR BOTTOM FRNC	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	105	160"PLATE HARDENING FURNC	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	106	160"PLATE TEMPERING FURNC	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	107	160 PLATE MILL ROLLING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	108	SLAB YD 1 FLAME CUTTING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	109	110"PLATE CONT FURNACE #1	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	110	110"PLATE CONT FURNACE #2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	111	EXTRA PROC BLDG FLAME CUT	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	113	110 PLATE MILL ROLLING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	114	BOF HT MTL DESULF STAT #1	None	None	Fabric Filter - High Temperature, I.E. T>250f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	115	BOF HT MTL DESULF STAT #2	None	None	Fabric Filter - High Temperature, I.E. T>250f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	117	BOF 1&2 CHRG,TAP,SLAGOFF	None	None	Venturi Scrubber	Venturi Scrubber
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	125	BOF 1 & 2 REFINING CYCLE	None	None	Venturi Scrubber	Direct Flame Afterburner
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	137	TEEMING POUR MOLDS	None	None	Process Enclosed	None

TABLE 4.1 LADCO BART CATEGORY 4 (IRON AND STEEL PLANT) EMISSION UNITS – EXISTING CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	140	TRACK HOPPER	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	143	JUNCTION HOUSE H1	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	144	JUNCTION HOUSE H2	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	145	BOF 1 & 2 STORAGE BINS	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	148	BOF WEIGH HOPPERS	None	None	Fabric Filter - Low Temperature, I.E. T<180f	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	153	CONTINUOUS CASTER #1	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	155	CASTER #1 SLAB PROCESSING	None	None	Process Enclosed	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	157	CASTER BLDGS MISC ACTIVTS	None	None	Process Enclosed	None

TABLE 4.2 LADCO BART CATEGORY 4 IRON AND STEEL PLANT EMISSION UNITS – RECOMMENDED BART CONTROLS

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO_2	NO_2	PM	VOC
ILLINOIS	National Steel Corp	0015	SLAB FURNACE #1	None	ULNB	None	None
ILLINOIS	National Steel Corp	0033	BOF - TWO VESSELS	None	ULNB	FF or DESP	None
ILLINOIS	National Steel Corp	0041	BOILER HOUSE 1: BOILERS 1 TO 7	Wet FGD	ULNB	FF or DESP	None
ILLINOIS	National Steel Corp	0042	BOILER HOUSE 1: BOILERS 8 TO 10	Wet FGD	ULNB	FF or DESP	None
ILLINOIS	National Steel Corp	0044	BOILER HOUSE 2: BOILER #11 - BLAST FURNACE DEPT	Wet FGD	ULNB	FF or DESP	None
ILLINOIS	National Steel Corp	0048	BOILER HOUSE 2: BOILER #12 - BLAST FURNACE DEPT	Wet FGD	ULNB	FF or DESP	None
ILLINOIS	National Steel Corp	0122	SLAB FURNACE #2	Vented to common wet FGD or none	ULNB or LNB	None	None
ILLINOIS	National Steel Corp	0123	SLAB FURNACE #3	Vented to common wet FGD or none	ULNB or LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	001	BEDDING PLANT MATL TRANS	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	002	SINTER MIXING DRUM	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	003	SINTER WINDBOX	AFGD or wet FGD	ULNB	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	004	SINTER MISC MATL HANDLING	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	005	SINTER TRANSFER STATIONS	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	006	BLAST FURNACE CAR DUMPER	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	007	BLAST FURNCE THAW SHED	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	008	BF C STOCKHOUSE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	009	BF D STOCKHOUSE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	010	BF C CASTHSE, STOVES, FLR	DFGD or AFGD	ULNB	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	011	BF D CASTHSE, STOVES, FLR	DFGD or AFGD	ULNB	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	036	COAL PREPARATION	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	037	BATTERY #1 PUSHING	None	None	Existing	None

TABLE 4.2 LADCO BART CATEGORY 4 IRON AND STEEL PLANT EMISSION UNITS – RECOMMENDED BART CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	039	COKE OVEN UNDRFIRE BAT #1	Wet FGD	ULNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	040	COKE BATTERY #1 QUENCHING	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	041	BATTERY #2 PUSHING	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	043	COKE OVEN UNDRFIRE BAT #2	Wet FGD	ULNB or LNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	044	BATTERY #2 QUENCHING	None	None	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	045	COKE OVEN COAL CHEM PLANT	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	046	COKE SCREENING	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	048	CSM #1 PICKLE LINE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	049	CSM #2 PICKLE LINE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	051	COLD SHEET MILL- TANDEM	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	052	BATCH ANNEAL FURNACES	None	LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	056	COLD SHEET MILL-DUO MILL	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	057	COLD SHEET TEMPER MILL	None	None	None	Existing
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	058	COLD SHEET SHIP BLDGS 1&2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	061	CSM EGL LINE CLEANING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	062	CSM EGL LINE PICKLING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	063	CSM EGL LINE ZINC PLATING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	067	NORTH BURNING BED	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	068	SOUTH BURNING BED	None	None	Existing	None

TABLE 4.2 LADCO BART CATEGORY 4 IRON AND STEEL PLANT EMISSION UNITS – RECOMMENDED BART CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	069	HAND SCARFING BED	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	070	HOT STRIP MILL FURN #1	Vented to common wet FGD or none	ULNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	071	HOT STRIP MILL FURN #2	Vented to common wet FGD or none	ULNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	072	HOT STRIP MILL FURN #3	Vented to common wet FGD or none	ULNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	073	HSM ROLLING PROCESS	None	None	Existing	Existing
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	076	POWER STATION BOILER #8	Wet FGD	ULNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	077	POWER STATION BOILER #9	Wet FGD	ULNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	078	POWER STATION BOILER #10	Wet FGD	ULNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	079	POWER STATION BOILER #11	Wet FGD	ULNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	080	POWER STATION BOILER #12	Wet FGD	ULNB	FF or DESP	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	081	#1 ROLL SHOP N. BAGHOUSE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	082	#1 ROLL SHOP S. BAGHOUSE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	083	#2 ROLL SHOP BAGHOUSE	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	084	36 SOAKING PITS	None	ULNB or LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	085	SLAB MILL SCARFER	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	086	SLAB MILL ROLLING PROCESS	None	None	Existing	None

TABLE 4.2 LADCO BART CATEGORY 4 IRON AND STEEL PLANT EMISSION UNITS – RECOMMENDED BART CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	088	SLAB YD 3 FURNACE 4&5&6	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	089	SLAB YD 3 SCARFING BED 3	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	091	SLAB YD 3 FLAME CUTTING	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	092	SLAB YD 2 FURNACE 1&2&3	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	093	SLAB YD 2 FLAME CUT BED 2	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	094	SLAB YD 2 SCARFING BED 2	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	095	160"PLATE CONT.FURNACE #1	Vented to common wet FGD or none	ULNB or LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	096	160"PLATE CONT FURNACE #2	Vented to common wet FGD or none	ULNB or LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	097	160"PLATE BATCH FURNCE #4	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	098	160"PLATE BATCH FURNCE #5	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	099	160"PLATE BATCH FURNCE #6	Vented to common wet FGD or none	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	100	160"PLATE BATCH FURNCE #7	Vented to common wet FGD or none	LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	101	160"PLATE BATCH FURNCE #8	Vented to common wet FGD or none	None	None	None

TABLE 4.2 LADCO BART CATEGORY 4 IRON AND STEEL PLANT EMISSION UNITS – RECOMMENDED BART CONTROLS (CONTINUED)

STATE	SOURCE NAME	EMISSION UNIT ID	EMISSION UNIT DESCRIPTION	SO2	NO2	PM	VOC
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	104	160"PLATE CAR BOTTOM FRNC	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	105	160"PLATE HARDENING FURNC	None	LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	106	160"PLATE TEMPERING FURNC	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	107	160 PLATE MILL ROLLING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	108	SLAB YD 1 FLAME CUTTING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	109	110"PLATE CONT FURNACE #1	None	LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	110	110"PLATE CONT FURNACE #2	None	LNB	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	111	EXTRA PROC BLDG FLAME CUT	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	113	110 PLATE MILL ROLLING	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	114	BOF HT MTL DESULF STAT #1	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	115	BOF HT MTL DESULF STAT #2	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	117	BOF 1&2 CHRG,TAP,SLAGOFF	None	None	Existing	Existing
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	125	BOF 1 & 2 REFINING CYCLE	None	ULNB	Existing	Existing
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	137	TEEMING POUR MOLDS	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	140	TRACK HOPPER	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	143	JUNCTION HOUSE H1	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	144	JUNCTION HOUSE H2	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	145	BOF 1 & 2 STORAGE BINS	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	148	BOF WEIGH HOPPERS	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	153	CONTINUOUS CASTER #1	None	None	None	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	155	CASTER #1 SLAB PROCESSING	None	None	Existing	None
INDIANA	ISG-BURNS HARBOR (Formerly Bethlehem Steel)	157	CASTER BLDGS MISC ACTIVTS	None	None	Existing	None

Appendix A

NO_X Boilers

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**205,109**
Instrumentation	10%	of control device cost (A)	20,511
Sales Taxes	6.0%	of control device cost (A)	12,307
Freight	5%	of control device cost (A)	10,255
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**248,182**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	9,927
Handling, erection	50%	of purchased equip cost (B)	124,091
Electrical	8%	of purchased equip cost (B)	19,855
Piping	1%	of purchased equip cost (B)	2,482
Insulation	7%	of purchased equip cost (B)	17,373
Painting	4%	of purchased equip cost (B)	9,927
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**183,655**
Total Direct Capital Cost			**431,836**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	24,818
Construction, field exp.	20%	of purchased equip cost (B)	49,636
Construction fee	10%	of purchased equip cost (B)	24,818
Startup	1%	of purchased equip cost (B)	2,482
Tests	1%	of purchased equip cost (B)	2,482
Contingencies	3%	of purchased equip cost (B)	7,445
Total Indirect Capital Costs	45%		**111,682**
Total Capital Investment (TCI)			**543,518**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**543,518**
Total Annualized Capital Costs			**51,304**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,435
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,435
Administration (2% total capital costs)	2%	of total capital costs (TCI)	10,870
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**128,573**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**221,120**
Pollutant Removed (tons/yr)			**281**
Cost per ton of NOx Removed			**786**

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BART ANALYSIS 2004
LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Annual hours of operation: 8,760**			
				Utilization rate:	**90%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,758	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**422.03**	
Emission Reduction T/yr					**281**	

	Flow acfm	D P in H2O	Blower Efi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
HIGH NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**2,618,557**
Instrumentation	10%	of control device cost (A)	261,856
Sales Taxes	6.0%	of control device cost (A)	157,113
Freight	5%	of control device cost (A)	130,928
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**3,168,455**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	126,738
Handling, erection	50%	of purchased equip cost (B)	1,584,227
Electrical	8%	of purchased equip cost (B)	253,476
Piping	1%	of purchased equip cost (B)	31,685
Insulation	7%	of purchased equip cost (B)	221,792
Painting	4%	of purchased equip cost (B)	126,738
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**2,344,656**
Total Direct Capital Cost			**5,513,111**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	316,845
Construction, field exp.	20%	of purchased equip cost (B)	633,691
Construction fee	10%	of purchased equip cost (B)	316,845
Startup	1%	of purchased equip cost (B)	31,685
Tests	1%	of purchased equip cost (B)	31,685
Contingencies	3%	of purchased equip cost (B)	95,054
Total Indirect Capital Costs	45%		**1,425,805**
Total Capital Investment (TCI)			**6,938,915**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**6,938,915**
Total Annualized Capital Costs			**654,985**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	69,389
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	69,389
Administration (2% total capital costs)	2%	of total capital costs (TCI)	138,778
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**988,069**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,080,616**
Pollutant Removed (tons/yr)			**281**
Cost per ton of NOx Removed			**3,841**

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BART ANALYSIS 2004
HIGH NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Annual hours of operation: 8,760**			
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,758	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**422.03**	
Emission Reduction T/yr					**281**	

	Flow acfm	D P in H2O	Blower Effi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**211,284**
Instrumentation	10%	of control device cost (A)	21,128
Sales Taxes	6.0%	of control device cost (A)	12,677
Freight	5%	of control device cost (A)	10,564
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	18%		**255,654**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	10,226
Handling, erection	50%	of purchased equip cost (B)	127,827
Electrical	8%	of purchased equip cost (B)	20,452
Piping	1%	of purchased equip cost (B)	2,557
Insulation	7%	of purchased equip cost (B)	17,896
Painting	4%	of purchased equip cost (B)	10,226
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**189,184**
Total Direct Capital Cost			**444,837**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,565
Construction, field exp.	20%	of purchased equip cost (B)	51,131
Construction fee	10%	of purchased equip cost (B)	25,565
Startup	1%	of purchased equip cost (B)	2,557
Tests	1%	of purchased equip cost (B)	2,557
Contingencies	3%	of purchased equip cost (B)	7,670
Total Indirect Capital Costs	45%		**115,044**
Total Capital Investment (TCI)			**559,881**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**559,881**
Total Annualized Capital Costs			**52,849**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,599
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,599
Administration (2% total capital costs)	2%	of total capital costs (TCI)	11,198
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**130,772**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**223,319**
Pollutant Removed (tons/yr)[B]			**281**
Cost per ton of NOx Removed			**794**

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BART ANALYSIS 2004
LOW NOX BURNER

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations **Annual hours of operation: 8,760**
Utilization rate: 90%

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBtu/hr	NA	**703**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**422.03**	
Emission Reduction T/yr					**281**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
HIGH NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**2,697,392**
Instrumentation	10%	of control device cost (A)	269,739
Sales Taxes	6.0%	of control device cost (A)	161,844
Freight	5%	of control device cost (A)	134,870
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	18%		**3,263,844**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	130,554
Handling, erection	50%	of purchased equip cost (B)	1,631,922
Electrical	8%	of purchased equip cost (B)	261,108
Piping	1%	of purchased equip cost (B)	32,638
Insulation	7%	of purchased equip cost (B)	228,469
Painting	4%	of purchased equip cost (B)	130,554
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**2,415,245**
Total Direct Capital Cost			**5,679,089**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	326,384
Construction, field exp.	20%	of purchased equip cost (B)	652,769
Construction fee	10%	of purchased equip cost (B)	326,384
Startup	1%	of purchased equip cost (B)	32,638
Tests	1%	of purchased equip cost (B)	32,638
Contingencies	3%	of purchased equip cost (B)	97,915
Total Indirect Capital Costs	45%		**1,468,730**
Total Capital Investment (TCI)			**7,147,819**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**7,147,819**
Total Annualized Capital Costs			**674,704**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	71,478
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	71,478
Administration (2% total capital costs)	2%	of total capital costs (TCI)	142,956
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,016,144**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,108,691**
Pollutant Removed (tons/yr)[B]			**281**
Cost per ton of NOx Removed			**3,941**

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BART ANALYSIS 2004
HIGH NOX BURNER

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**422.03**	
Emission Reduction T/yr					**281**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		The cost of the fan + duct	**125,000**
Instrumentation	10%	of control device cost (A)	12,500
Sales Taxes	6.0%	of control device cost (A)	7,500
Freight	5%	of control device cost (A)	6,250
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	21%		**151,250**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	6,050
Handling, erection	50%	of purchased equip cost (B)	75,625
Electrical	8%	of purchased equip cost (B)	12,100
Piping	1%	of purchased equip cost (B)	1,513
Insulation	7%	of purchased equip cost (B)	10,588
Painting	4%	of purchased equip cost (B)	6,050
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**111,925**
Total Direct Capital Cost			**263,175**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	15,125
Construction, field exp.	20%	of purchased equip cost (B)	30,250
Construction fee	10%	of purchased equip cost (B)	15,125
Startup	1%	of purchased equip cost (B)	1,513
Tests	1%	of purchased equip cost (B)	1,513
Contingencies	3%	of purchased equip cost (B)	4,538
Total Indirect Capital Costs	45%		**68,063**
Total Capital Investment (TCI)			**331,238**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**331,238**
Total Annualized Capital Costs			**31,266**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.047	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity	82,787
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**175,334**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	3,312
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	3,312
Administration (2% total capital costs)	2%	of total capital costs (TCI)	6,625
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**100,044**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**275,379**
Pollutant Removed (tons/yr)[B]			**211**
Cost per ton of NOx Removed			**1,305**

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	224	kW-hr	1,764,439	82,787	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	52,560	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**492.36**	
Emission Reduction T/yr					**211**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	101,676	5	0.55	0.9	120.2	OAQPS Cost Cont Manual 5th ed - Eq 3.37

	brake horse power	kW
Fan motor	300	224

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		The cost of the fan + duct	**250,000**
Instrumentation	10%	of control device cost (A)	25,000
Sales Taxes	6.0%	of control device cost (A)	15,000
Freight	5%	of control device cost (A)	12,500
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	21%		**302,500**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	12,100
Handling, erection	50%	of purchased equip cost (B)	151,250
Electrical	8%	of purchased equip cost (B)	24,200
Piping	1%	of purchased equip cost (B)	3,025
Insulation	7%	of purchased equip cost (B)	21,175
Painting	4%	of purchased equip cost (B)	12,100
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**223,850**
Total Direct Capital Cost			**526,350**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	30,250
Construction, field exp.	20%	of purchased equip cost (B)	60,500
Construction fee	10%	of purchased equip cost (B)	30,250
Startup	1%	of purchased equip cost (B)	3,025
Tests	1%	of purchased equip cost (B)	3,025
Contingencies	3%	of purchased equip cost (B)	9,075
Total Indirect Capital Costs	45%		**136,125**
Total Capital Investment (TCI)			**662,475**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**662,475**
Total Annualized Capital Costs			**62,533**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.047	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity	82,787
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**175,334**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,625
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,625
Administration (2% total capital costs)	2%	of total capital costs (TCI)	13,250
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**144,560**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**319,895**
Pollutant Removed (tons/yr)[B]			**211**
Cost per ton of NOx Removed			**1,516**

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	224	kW-hr	1,764,439	82,787	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	52,560	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**492.36**	
Emission Reduction T/yr					**211**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	101,676	5	0.55	0.9	120.2	OAQPS Cost Cont Manual 5th ed - Eq 3.37

	brake horse power	kW
Fan motor	300	224

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**718,504**
Instrumentation	1%	of control device cost (A)	7,185
Sales Taxes	6.0%	of control device cost (A)	43,110
Freight	5%	of control device cost (A)	35,925
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**804,724**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	64,378
Handling, erection	14%	of purchased equip cost (B)	112,661
Electrical	4%	of purchased equip cost (B)	32,189
Piping	4%	of purchased equip cost (B)	32,189
Insulation	1%	of purchased equip cost (B)	8,047
Painting	1%	of purchased equip cost (B)	8,047
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**257,512**
Total Direct Capital Cost			**1,062,236**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	80,472
Construction, field exp.	5%	of purchased equip cost (B)	40,236
Construction fee	10%	of purchased equip cost (B)	80,472
Startup	2%	of purchased equip cost (B)	16,094
Tests	1%	of purchased equip cost (B)	8,047
Contingencies	3%	of purchased equip cost (B)	24,142
Total Indirect Capital Costs	31%		**249,464**
Total Capital Investment (TCI)			**1,311,700**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,311,700**
Total Annualized Capital Costs			**123,815**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity	222,254
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity	3,765
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	294,983
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**557,282**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	13,117
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	13,117
Administration (2% total capital costs)	2%	of total capital costs (TCI)	26,234
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**197,544**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**754,826**
Pollutant Removed (tons/yr)			**211**
Cost per ton of NOx Removed			**3,577**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Utilization Rate** **90.0%**; **Annual hours of operation:** **8,760**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	600.8	kW-hr	4,736,872	222,254	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	29.0	scfm	13,734,410	3,765	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.10	Lb	362.9	lb/hr	2,861,335	294,983	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBTU/	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**492.36**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**211**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	5	0.55	0.9	600.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.64	50	0.8	0.9	0.01	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					600.8	

Ammonia	160.6	lb/hr NOx	0.370	lb NH3/lb NOx	62.9	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	362.9	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			29.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**2,630,514**
Instrumentation	1%	of control device cost (A)	26,305
Sales Taxes	6.0%	of control device cost (A)	157,831
Freight	5%	of control device cost (A)	131,526
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**2,946,176**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	235,694
Handling, erection	14%	of purchased equip cost (B)	412,465
Electrical	4%	of purchased equip cost (B)	117,847
Piping	4%	of purchased equip cost (B)	117,847
Insulation	1%	of purchased equip cost (B)	29,462
Painting	1%	of purchased equip cost (B)	29,462
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**942,776**
Total Direct Capital Cost			**3,888,952**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	294,618
Construction, field exp.	5%	of purchased equip cost (B)	147,309
Construction fee	10%	of purchased equip cost (B)	294,618
Startup	2%	of purchased equip cost (B)	58,924
Tests	1%	of purchased equip cost (B)	29,462
Contingencies	3%	of purchased equip cost (B)	88,385
Total Indirect Capital Costs	31%		**913,315**
Total Capital Investment (TCI)			**4,802,267**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**4,802,267**
Total Annualized Capital Costs			**453,300**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity	222,254
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity	3,765
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	294,983
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**557,282**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	48,023
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	48,023
Administration (2% total capital costs)	2%	of total capital costs (TCI)	96,045
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**666,652**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,223,933**
Pollutant Removed (tons/yr)			**211**
Cost per ton of NOx Removed			**5,800**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations					**Utilization Rate**		**90.0%**	
					Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Supervisor	NA				NA	NA	15% of Operator Costs	
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Maint Mtls	NA				NA	NA	of purchased equipment costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.047	kW-hr	600.8	kW-hr	4,736,872	222,254	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	29.0	scfm	13,734,410	3,765	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity	
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia	
Reagent #2 (Urea 50% Solution)	0.10	Lb	362.9	lb/hr	2,861,335	294,983	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr	
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr	
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity	
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBTU/	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**492.36**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**211**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	5	0.55	0.9	600.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.64	50	0.8	0.9	0.01	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					600.8	

Ammonia	160.6	lb/hr NOx	0.370	lb NH3/lb NOx	62.9	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	362.9	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			29.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**718,504**
Instrumentation	1%	of control device cost (A)	7,185
Sales Taxes	6.0%	of control device cost (A)	43,110
Freight	5%	of control device cost (A)	35,925
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**804,724**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	64,378
Handling, erection	14%	of purchased equip cost (B)	112,661
Electrical	4%	of purchased equip cost (B)	32,189
Piping	4%	of purchased equip cost (B)	32,189
Insulation	1%	of purchased equip cost (B)	8,047
Painting	1%	of purchased equip cost (B)	8,047
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**257,512**
Total Direct Capital Cost			**1,062,236**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	80,472
Construction, field exp.	5%	of purchased equip cost (B)	40,236
Construction fee	10%	of purchased equip cost (B)	80,472
Startup	2%	of purchased equip cost (B)	16,094
Tests	1%	of purchased equip cost (B)	8,047
Contingencies	3%	of purchased equip cost (B)	24,142
Total Indirect Capital Costs	31%		**249,464**
Total Capital Investment (TCI)			**1,311,700**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,311,700**
Total Annualized Capital Costs			**123,815**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity	222,254
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity	3,765
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	294,983
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**557,282**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	13,117
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	13,117
Administration (2% total capital costs)	2%	of total capital costs (TCI)	26,234
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**197,544**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**754,826**
Pollutant Removed (tons/yr)			**352**
Cost per ton of NOx Removed			**2,146**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	600.8	kW-hr	4,736,872	222,254	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	29.0	scfm	13,734,410	3,765	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.10	Lb	362.9	lb/hr	2,861,335	294,983	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perio	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBTU/	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				50%	**351.69**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**352**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	5	0.55	0.9	600.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.64	50	0.8	0.9	0.01	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					600.8	

Ammonia	160.6	lb/hr NOx	0.370	lb NH3/lb NOx	62.9	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	362.9	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			29.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**2,630,514**
Instrumentation	1%	of control device cost (A)	26,305
Sales Taxes	6.0%	of control device cost (A)	157,831
Freight	5%	of control device cost (A)	131,526
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**2,946,176**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	235,694
Handling, erection	14%	of purchased equip cost (B)	412,465
Electrical	4%	of purchased equip cost (B)	117,847
Piping	4%	of purchased equip cost (B)	117,847
Insulation	1%	of purchased equip cost (B)	29,462
Painting	1%	of purchased equip cost (B)	29,462
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**942,776**
Total Direct Capital Cost			**3,888,952**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	294,618
Construction, field exp.	5%	of purchased equip cost (B)	147,309
Construction fee	10%	of purchased equip cost (B)	294,618
Startup	2%	of purchased equip cost (B)	58,924
Tests	1%	of purchased equip cost (B)	29,462
Contingencies	3%	of purchased equip cost (B)	88,385
Total Indirect Capital Costs	31%		**913,315**
Total Capital Investment (TCI)			**4,802,267**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**4,802,267**
Total Annualized Capital Costs			**453,300**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity	222,254
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity	3,765
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	294,983
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**557,282**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	48,023
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	48,023
Administration (2% total capital costs)	2%	of total capital costs (TCI)	96,045
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**666,652**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,223,933**
Pollutant Removed (tons/yr)			**352**
Cost per ton of NOx Removed			**3,480**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	600.8	kW-hr	4,736,872	222,254	$/kW-hr, 601 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	29.0	scfm	13,734,410	3,765	$/Mscf, 29.0 scfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.10	Lb	362.9	lb/hr	2,861,335	294,983	$/Lb, 362.9 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu		650 MMBTU/	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				50%	**351.69**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**352**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	5	0.55	0.9	600.8	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.64	50	0.8	0.9	0.01	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					600.8	

Ammonia	160.6	lb/hr NOx	0.370	lb NH3/lb NOx	62.9	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	362.9	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			29.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**1,021,979**
Instrumentation	10% of control device cost (A)	102,198
Sales Taxes	6.0% of control device cost (A)	61,319
Freight	5% of control device cost (A)	51,099
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**1,236,595**
Installation		
Foundations & supports	8% of purchased equip cost (B)	98,928
Handling, erection	14% of purchased equip cost (B)	173,123
Electrical	4% of purchased equip cost (B)	49,464
Piping	4% of purchased equip cost (B)	49,464
Insulation	1% of purchased equip cost (B)	12,366
Painting	1% of purchased equip cost (B)	12,366
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**395,710**
Total Direct Capital Cost		**1,632,306**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	123,660
Construction, field exp.	5% of purchased equip cost (B)	61,830
Construction fee	10% of purchased equip cost (B)	123,660
Startup	2% of purchased equip cost (B)	24,732
Tests	1% of purchased equip cost (B)	12,366
Contingencies	3% of purchased equip cost (B)	37,098
Total Indirect Capital Costs	31%	**383,344**
Total Capital Investment (TCI)		**2,015,650**
Replacement Parts Cost & Installation Labor	1,377,791 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**637,859**
Total Annualized Capital Costs		**60,209**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.38 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15% of oper labor costs	1,876
Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,387,084**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	20,157
Insurance (1% total capital costs)	1% of total capital costs (TCI)	20,157
Administration (2% total capital costs)	2% of total capital costs (TCI)	40,313
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**159,970**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**1,547,054**
Pollutant Removed (tons/yr)		**492**
Cost per ton of NOx Removed		**3,142**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	$/ft^3	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		90.0%	
				Annual hours of operation:		8,760	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	$/Ton, 68.3 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation						
Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**211.01**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**492**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**8,515,946**
Instrumentation	10%	of control device cost (A)	851,595
Sales Taxes	6.0%	of control device cost (A)	510,957
Freight	5%	of control device cost (A)	425,797
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**10,304,294**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	824,344
Handling, erection	14%	of purchased equip cost (B)	1,442,601
Electrical	4%	of purchased equip cost (B)	412,172
Piping	4%	of purchased equip cost (B)	412,172
Insulation	1%	of purchased equip cost (B)	103,043
Painting	1%	of purchased equip cost (B)	103,043
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**3,297,374**
Total Direct Capital Cost			**13,601,669**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,030,429
Construction, field exp.	5%	of purchased equip cost (B)	515,215
Construction fee	10%	of purchased equip cost (B)	1,030,429
Startup	2%	of purchased equip cost (B)	206,086
Tests	1%	of purchased equip cost (B)	103,043
Contingencies	3%	of purchased equip cost (B)	309,129
Total Indirect Capital Costs	31%		**3,194,331**
Total Capital Investment (TCI)			**16,796,000**
Replacement Parts Cost & Installation Labor	1,377,791	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**15,418,209**
Total Annualized Capital Costs			**1,455,370**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	\$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	\$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	\$/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	\$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,387,084**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	167,960
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	167,960
Administration (2% total capital costs)	2%	of total capital costs (TCI)	335,920
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,146,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**3,533,429**
Pollutant Removed (tons/yr)			**492**
Cost per ton of NOx Removed			**7,176**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations					**Utilization Rate**		**90.0%**	
					Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Supervisor	NA				NA	NA	15% of Operator Costs	
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Maint Mtls	NA				NA	NA	of purchased equipment costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	\$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity	
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	\$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.	
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	\$/Ton, 68.3 ton/yr	
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr	
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	\$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation						
Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**211.01**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**492**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**8,515,946**
Instrumentation	10% of control device cost (A)	851,595
Sales Taxes	6.0% of control device cost (A)	510,957
Freight	5% of control device cost (A)	425,797
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**10,304,294**
Installation		
Foundations & supports	8% of purchased equip cost (B)	824,344
Handling, erection	14% of purchased equip cost (B)	1,442,601
Electrical	4% of purchased equip cost (B)	412,172
Piping	4% of purchased equip cost (B)	412,172
Insulation	1% of purchased equip cost (B)	103,043
Painting	1% of purchased equip cost (B)	103,043
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**3,297,374**
Total Direct Capital Cost		**13,601,669**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	1,030,429
Construction, field exp.	5% of purchased equip cost (B)	515,215
Construction fee	10% of purchased equip cost (B)	1,030,429
Startup	2% of purchased equip cost (B)	206,086
Tests	1% of purchased equip cost (B)	103,043
Contingencies	3% of purchased equip cost (B)	309,129
Total Indirect Capital Costs	31%	**3,194,331**
Total Capital Investment (TCI)		**16,796,000**
Replacement Parts Cost & Installation Labor	1,377,791 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**15,418,209**
Total Annualized Capital Costs		**1,455,370**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.38 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15% of oper labor costs	1,876
Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,387,084**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	167,960
Insurance (1% total capital costs)	1% of total capital costs (TCI)	167,960
Administration (2% total capital costs)	2% of total capital costs (TCI)	335,920
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**2,146,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**3,533,429**
Pollutant Removed (tons/yr)		**492**
Cost per ton of NOx Removed		**7,176**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	$/$ft^3$	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	$/Ton, 68.3 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**211.01**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**492**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**8,515,946**
Instrumentation	10% of control device cost (A)	851,595
Sales Taxes	6.0% of control device cost (A)	510,957
Freight	5% of control device cost (A)	425,797
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**10,304,294**
Installation		
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Handling, erection	14% of purchased equip cost (B)	1,442,601
Electrical	4% of purchased equip cost (B)	412,172
Piping	4% of purchased equip cost (B)	412,172
Insulation	1% of purchased equip cost (B)	103,043
Painting	1% of purchased equip cost (B)	103,043
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**3,297,374**
Total Direct Capital Cost		**13,601,669**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	1,030,429
Construction, field exp.	5% of purchased equip cost (B)	515,215
Construction fee	10% of purchased equip cost (B)	1,030,429
Startup	2% of purchased equip cost (B)	206,086
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OPERATING COSTS		
Direct Operating Costs		
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Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,387,084**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	167,960
Insurance (1% total capital costs)	1% of total capital costs (TCI)	167,960
Administration (2% total capital costs)	2% of total capital costs (TCI)	335,920
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**2,146,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**3,533,429**
Pollutant Removed (tons/yr)		**633**
Cost per ton of NOx Removed		**5,582**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	$/$ft^3$	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	$/Ton, 68.3 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**70.34**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**633**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**809,204**
Instrumentation	10%	of control device cost (A)	80,920
Sales Taxes	6.0%	of control device cost (A)	48,552
Freight	5%	of control device cost (A)	40,460
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**979,136**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	39,165
Handling, erection	50%	of purchased equip cost (B)	489,568
Electrical	8%	of purchased equip cost (B)	78,331
Piping	1%	of purchased equip cost (B)	9,791
Insulation	7%	of purchased equip cost (B)	68,540
Painting	4%	of purchased equip cost (B)	39,165
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**724,561**
Total Direct Capital Cost			**1,703,697**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	97,914
Construction, field exp.	20%	of purchased equip cost (B)	195,827
Construction fee	10%	of purchased equip cost (B)	97,914
Startup	1%	of purchased equip cost (B)	9,791
Tests	1%	of purchased equip cost (B)	9,791
Contingencies	3%	of purchased equip cost (B)	29,374
Total Indirect Capital Costs	45%		**440,611**
Total Capital Investment (TCI)			**2,144,309**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,144,309**
Total Annualized Capital Costs			**202,408**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Administration (2% total capital costs)	2%	of total capital costs (TCI)	42,886
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**343,708**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**448,261**
Pollutant Removed (tons/yr)			**527.5**
Cost per ton of NOx Removed			**850**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBtu/hr	NA	**703**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				75%	**175.84**	
Emission Reduction T/yr					**527.53**	

	Flow acfm	D P in H2O	Blower Effi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**809,204**
Instrumentation	10%	of control device cost (A)	80,920
Sales Taxes	6.0%	of control device cost (A)	48,552
Freight	5%	of control device cost (A)	40,460
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**979,136**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	39,165
Handling, erection	50%	of purchased equip cost (B)	489,568
Electrical	8%	of purchased equip cost (B)	78,331
Piping	1%	of purchased equip cost (B)	9,791
Insulation	7%	of purchased equip cost (B)	68,540
Painting	4%	of purchased equip cost (B)	39,165
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**724,561**
Total Direct Capital Cost			**1,703,697**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	97,914
Construction, field exp.	20%	of purchased equip cost (B)	195,827
Construction fee	10%	of purchased equip cost (B)	97,914
Startup	1%	of purchased equip cost (B)	9,791
Tests	1%	of purchased equip cost (B)	9,791
Contingencies	3%	of purchased equip cost (B)	29,374
Total Indirect Capital Costs	45%		**440,611**
Total Capital Investment (TCI)			**2,144,309**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,144,309**
Total Annualized Capital Costs			**202,408**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Administration (2% total capital costs)	2%	of total capital costs (TCI)	42,886
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**343,708**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**448,261**
Pollutant Removed (tons/yr)			**597.9**
Cost per ton of NOx Removed			**750**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBtu/hı	NA	**703**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				85%	**105.51**	
Emission Reduction T/yr					**597.87**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**809,204**
Instrumentation	10%	of control device cost (A)	80,920
Sales Taxes	6.0%	of control device cost (A)	48,552
Freight	5%	of control device cost (A)	40,460
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**979,136**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	39,165
Handling, erection	50%	of purchased equip cost (B)	489,568
Electrical	8%	of purchased equip cost (B)	78,331
Piping	1%	of purchased equip cost (B)	9,791
Insulation	7%	of purchased equip cost (B)	68,540
Painting	4%	of purchased equip cost (B)	39,165
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**724,561**
Total Direct Capital Cost			**1,703,697**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	97,914
Construction, field exp.	20%	of purchased equip cost (B)	195,827
Construction fee	10%	of purchased equip cost (B)	97,914
Startup	1%	of purchased equip cost (B)	9,791
Tests	1%	of purchased equip cost (B)	9,791
Contingencies	3%	of purchased equip cost (B)	29,374
Total Indirect Capital Costs	45%		**440,611**
Total Capital Investment (TCI)			**2,144,309**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,144,309**
Total Annualized Capital Costs			**202,408**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Administration (2% total capital costs)	2%	of total capital costs (TCI)	42,886
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**343,708**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**448,261**
Pollutant Removed (tons/yr)			**527.5**
Cost per ton of NOx Removed			**850**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations **Annual hours of operation: 8,760**
Utilization rate: 90%

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				75%	**175.84**	
Emission Reduction T/yr					**527.53**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**809,204**
Instrumentation	10%	of control device cost (A)	80,920
Sales Taxes	6.0%	of control device cost (A)	48,552
Freight	5%	of control device cost (A)	40,460
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**979,136**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	39,165
Handling, erection	50%	of purchased equip cost (B)	489,568
Electrical	8%	of purchased equip cost (B)	78,331
Piping	1%	of purchased equip cost (B)	9,791
Insulation	7%	of purchased equip cost (B)	68,540
Painting	4%	of purchased equip cost (B)	39,165
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**724,561**
Total Direct Capital Cost			**1,703,697**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	97,914
Construction, field exp.	20%	of purchased equip cost (B)	195,827
Construction fee	10%	of purchased equip cost (B)	97,914
Startup	1%	of purchased equip cost (B)	9,791
Tests	1%	of purchased equip cost (B)	9,791
Contingencies	3%	of purchased equip cost (B)	29,374
Total Indirect Capital Costs	45%		**440,611**
Total Capital Investment (TCI)			**2,144,309**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,144,309**
Total Annualized Capital Costs			**202,408**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	21,443
Administration (2% total capital costs)	2%	of total capital costs (TCI)	42,886
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**343,708**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**448,261**
Pollutant Removed (tons/yr)			**597.9**
Cost per ton of NOx Removed			**750**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	650	MMBtu/hr	NA	**703**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				85%	**105.51**	
Emission Reduction T/yr					**597.87**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**1,021,979**
Instrumentation	10% of control device cost (A)	102,198
Sales Taxes	6.0% of control device cost (A)	61,319
Freight	5% of control device cost (A)	51,099
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**1,236,595**
Installation		
Foundations & supports	8% of purchased equip cost (B)	98,928
Handling, erection	14% of purchased equip cost (B)	173,123
Electrical	4% of purchased equip cost (B)	49,464
Piping	4% of purchased equip cost (B)	49,464
Insulation	1% of purchased equip cost (B)	12,366
Painting	1% of purchased equip cost (B)	12,366
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**395,710**
Total Direct Capital Cost		**1,632,306**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	123,660
Construction, field exp.	5% of purchased equip cost (B)	61,830
Construction fee	10% of purchased equip cost (B)	123,660
Startup	2% of purchased equip cost (B)	24,732
Tests	1% of purchased equip cost (B)	12,366
Contingencies	3% of purchased equip cost (B)	37,098
Total Indirect Capital Costs	31%	**383,344**
Total Capital Investment (TCI)		**2,015,650**
Replacement Parts Cost & Installation Labor	1,377,791 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**637,859**
Total Annualized Capital Costs		**60,209**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.38 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15% of oper labor costs	1,876
Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,387,084**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	20,157
Insurance (1% total capital costs)	1% of total capital costs (TCI)	20,157
Administration (2% total capital costs)	2% of total capital costs (TCI)	40,313
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**159,970**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**1,547,054**
Pollutant Removed (tons/yr)		**492**
Cost per ton of NOx Removed		**3,142**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	\$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	\$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	\$/Ton, 68.3 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	\$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**211.01**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**492**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**8,515,946**
Instrumentation	10%	of control device cost (A)	851,595
Sales Taxes	6.0%	of control device cost (A)	510,957
Freight	5%	of control device cost (A)	425,797
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**10,304,294**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	824,344
Handling, erection	14%	of purchased equip cost (B)	1,442,601
Electrical	4%	of purchased equip cost (B)	412,172
Piping	4%	of purchased equip cost (B)	412,172
Insulation	1%	of purchased equip cost (B)	103,043
Painting	1%	of purchased equip cost (B)	103,043
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**3,297,374**
Total Direct Capital Cost			**13,601,669**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,030,429
Construction, field exp.	5%	of purchased equip cost (B)	515,215
Construction fee	10%	of purchased equip cost (B)	1,030,429
Startup	2%	of purchased equip cost (B)	206,086
Tests	1%	of purchased equip cost (B)	103,043
Contingencies	3%	of purchased equip cost (B)	309,129
Total Indirect Capital Costs	31%		**3,194,331**
Total Capital Investment (TCI)			**16,796,000**
Replacement Parts Cost & Installation Labor	1,377,791	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**15,418,209**
Total Annualized Capital Costs			**1,455,370**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,387,084**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	167,960
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	167,960
Administration (2% total capital costs)	2%	of total capital costs (TCI)	335,920
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,146,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**3,533,429**
Pollutant Removed (tons/yr)			**492**
Cost per ton of NOx Removed			**7,176**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	$/$ft^3$	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	$/Ton, 68.3 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**211.01**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**492**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**8,515,946**
Instrumentation	10% of control device cost (A)	851,595
Sales Taxes	6.0% of control device cost (A)	510,957
Freight	5% of control device cost (A)	425,797
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**10,304,294**
Installation		
Foundations & supports	8% of purchased equip cost (B)	824,344
Handling, erection	14% of purchased equip cost (B)	1,442,601
Electrical	4% of purchased equip cost (B)	412,172
Piping	4% of purchased equip cost (B)	412,172
Insulation	1% of purchased equip cost (B)	103,043
Painting	1% of purchased equip cost (B)	103,043
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**3,297,374**
Total Direct Capital Cost		**13,601,669**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	1,030,429
Construction, field exp.	5% of purchased equip cost (B)	515,215
Construction fee	10% of purchased equip cost (B)	1,030,429
Startup	2% of purchased equip cost (B)	206,086
Tests	1% of purchased equip cost (B)	103,043
Contingencies	3% of purchased equip cost (B)	309,129
Total Indirect Capital Costs	31%	**3,194,331**
Total Capital Investment (TCI)		**16,796,000**
Replacement Parts Cost & Installation Labor	1,377,791 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**15,418,209**
Total Annualized Capital Costs		**1,455,370**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.38 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15% of oper labor costs	1,876
Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,387,084**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	167,960
Insurance (1% total capital costs)	1% of total capital costs (TCI)	167,960
Administration (2% total capital costs)	2% of total capital costs (TCI)	335,920
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**2,146,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**3,533,429**
Pollutant Removed (tons/yr)		**492**
Cost per ton of NOx Removed		**7,176**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations					**Utilization Rate**		**90.0%**	
					Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Supervisor	NA				NA	NA	15% of Operator Costs	
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Maint Mtls	NA				NA	NA	of purchased equipment costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	\$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity	
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	\$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.	
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	\$/Ton, 68.3 ton/yr	
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr	
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	\$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**211.01**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**492**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**8,515,946**
Instrumentation	10%	of control device cost (A)	851,595
Sales Taxes	6.0%	of control device cost (A)	510,957
Freight	5%	of control device cost (A)	425,797
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**10,304,294**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	824,344
Handling, erection	14%	of purchased equip cost (B)	1,442,601
Electrical	4%	of purchased equip cost (B)	412,172
Piping	4%	of purchased equip cost (B)	412,172
Insulation	1%	of purchased equip cost (B)	103,043
Painting	1%	of purchased equip cost (B)	103,043
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**3,297,374**
Total Direct Capital Cost			**13,601,669**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	1,030,429
Construction, field exp.	5%	of purchased equip cost (B)	515,215
Construction fee	10%	of purchased equip cost (B)	1,030,429
Startup	2%	of purchased equip cost (B)	206,086
Tests	1%	of purchased equip cost (B)	103,043
Contingencies	3%	of purchased equip cost (B)	309,129
Total Indirect Capital Costs	31%		**3,194,331**
Total Capital Investment (TCI)			**16,796,000**
Replacement Parts Cost & Installation Labor	1,377,791	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**15,418,209**
Total Annualized Capital Costs			**1,455,370**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity	506,733
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia	84,683
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 68.3 ton/yr	1,733
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity	762,045
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,387,084**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	167,960
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	167,960
Administration (2% total capital costs)	2%	of total capital costs (TCI)	335,920
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,146,345**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**3,533,429**
Pollutant Removed (tons/yr)			**633**
Cost per ton of NOx Removed			**5,582**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	$/$ft^3$	136.5	2	68.3
Amount Required	7801.4	ft^3			
Catalyst Cost	1,377,791	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,377,791**				
Annualized Cost	**762,045**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,377,791**

Design Flow	264,000	dscfm	300,000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1369.9	kW-hr	10,799,928	506,733	$/kW-hr, 1,370 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	57.0	lb/hr	411,914	84,683	$/Ton, 57.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	68.3	ton/yr	68	1,733	$/Ton, 68.3 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	7801.4	ft^3	2	762,045	$/ft3, 7,801.4 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2	0	$/$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	650	MMBTU/HR	NA	703	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**70.34**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					633	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	508,380	11.4	0.55	0.9	1369.9	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.09	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1369.9**	

Ammonia	144.5	lb/hr NOx	0.370	lb NH3/lb NOx	57.0	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	160.6	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	224.0	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	508,380	
Vol #2	**7801.4**	ft3

NO_X Furnaces

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**42,284**
Instrumentation	10%	of control device cost (A)	4,228
Sales Taxes	6.0%	of control device cost (A)	2,537
Freight	5%	of control device cost (A)	2,114
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**51,164**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	2,047
Handling, erection	50%	of purchased equip cost (B)	25,582
Electrical	8%	of purchased equip cost (B)	4,093
Piping	1%	of purchased equip cost (B)	512
Insulation	7%	of purchased equip cost (B)	3,581
Painting	4%	of purchased equip cost (B)	2,047
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**37,861**
Total Direct Capital Cost			**89,025**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,116
Construction, field exp.	20%	of purchased equip cost (B)	10,233
Construction fee	10%	of purchased equip cost (B)	5,116
Startup	1%	of purchased equip cost (B)	512
Tests	1%	of purchased equip cost (B)	512
Contingencies	3%	of purchased equip cost (B)	1,535
Total Indirect Capital Costs	45%		**23,024**
Total Capital Investment (TCI)			**112,048**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**112,048**
Total Annualized Capital Costs			**10,577**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,120
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,120
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,241
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**70,587**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**163,134**
Pollutant Removed (tons/yr)			**58**
Cost per ton of NOx Removed			**2,813**

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BART ANALYSIS 2004
LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,758	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**87.00**	
Emission Reduction T/yr					**58**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**539,826**
Instrumentation	10%	of control device cost (A)	53,983
Sales Taxes	6.0%	of control device cost (A)	32,390
Freight	5%	of control device cost (A)	26,991
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	0
Purchased Equipment Total (B)	18%		**653,189**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	26,128
Handling, erection	50%	of purchased equip cost (B)	326,595
Electrical	8%	of purchased equip cost (B)	52,255
Piping	1%	of purchased equip cost (B)	6,532
Insulation	7%	of purchased equip cost (B)	45,723
Painting	4%	of purchased equip cost (B)	26,128
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**483,360**
Total Direct Capital Cost			**1,136,549**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	65,319
Construction, field exp.	20%	of purchased equip cost (B)	130,638
Construction fee	10%	of purchased equip cost (B)	65,319
Startup	1%	of purchased equip cost (B)	6,532
Tests	1%	of purchased equip cost (B)	6,532
Contingencies	3%	of purchased equip cost (B)	19,596
Total Indirect Capital Costs	45%		**293,935**
Total Capital Investment (TCI)			**1,430,484**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,430,484**
Total Annualized Capital Costs			**135,028**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	14,305
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	14,305
Administration (2% total capital costs)	2%	of total capital costs (TCI)	28,610
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**247,775**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**340,322**
Pollutant Removed (tons/yr)			**58**
Cost per ton of NOx Removed			**5,867**

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BART ANALYSIS 2004
LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations **Annual hours of operation: 8,760**
Utilization rate: 90%

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,758	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**87.00**	
Emission Reduction T/yr					**58**	

	Flow acfm	D P in H2O	Blower Effi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**43,557**
Instrumentation	10%	of control device cost (A)	4,356
Sales Taxes	6.0%	of control device cost (A)	2,613
Freight	5%	of control device cost (A)	2,178
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	18%		**52,704**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	2,108
Handling, erection	50%	of purchased equip cost (B)	26,352
Electrical	8%	of purchased equip cost (B)	4,216
Piping	1%	of purchased equip cost (B)	527
Insulation	7%	of purchased equip cost (B)	3,689
Painting	4%	of purchased equip cost (B)	2,108
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**39,001**
Total Direct Capital Cost			**91,705**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,270
Construction, field exp.	20%	of purchased equip cost (B)	10,541
Construction fee	10%	of purchased equip cost (B)	5,270
Startup	1%	of purchased equip cost (B)	527
Tests	1%	of purchased equip cost (B)	527
Contingencies	3%	of purchased equip cost (B)	1,581
Total Indirect Capital Costs	45%		**23,717**
Total Capital Investment (TCI)			**115,422**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**115,422**
Total Annualized Capital Costs			**10,895**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,154
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,154
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,308
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**71,040**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**163,587**
Pollutant Removed (tons/yr)[B]			**58**
Cost per ton of NOx Removed			**2,820**

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BART ANALYSIS 2004
LOW NOX BURNER

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**87.00**	
Emission Reduction T/yr					**58**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**556,078**
Instrumentation	10%	of control device cost (A)	55,608
Sales Taxes	6.0%	of control device cost (A)	33,365
Freight	5%	of control device cost (A)	27,804
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	18%		**672,854**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	26,914
Handling, erection	50%	of purchased equip cost (B)	336,427
Electrical	8%	of purchased equip cost (B)	53,828
Piping	1%	of purchased equip cost (B)	6,729
Insulation	7%	of purchased equip cost (B)	47,100
Painting	4%	of purchased equip cost (B)	26,914
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**497,912**
Total Direct Capital Cost			**1,170,766**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	67,285
Construction, field exp.	20%	of purchased equip cost (B)	134,571
Construction fee	10%	of purchased equip cost (B)	67,285
Startup	1%	of purchased equip cost (B)	6,729
Tests	1%	of purchased equip cost (B)	6,729
Contingencies	3%	of purchased equip cost (B)	20,186
Total Indirect Capital Costs	45%		**302,784**
Total Capital Investment (TCI)			**1,473,550**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,473,550**
Total Annualized Capital Costs			**139,093**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	14,736
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	14,736
Administration (2% total capital costs)	2%	of total capital costs (TCI)	29,471
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**253,563**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**346,110**
Pollutant Removed (tons/yr)[B]			**58**
Cost per ton of NOx Removed			**5,967**

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BART ANALYSIS 2004
LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Enter Data in Blue Highlighted Cells
Data to Summary Table in Yellow Highlighted Cells

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBtu/hr	NA	145	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**87.00**	
Emission Reduction T/yr					**58**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		The cost of the fan + duct	**125,000**
Instrumentation	10%	of control device cost (A)	12,500
Sales Taxes	6.0%	of control device cost (A)	7,500
Freight	5%	of control device cost (A)	6,250
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	21%		**151,250**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	6,050
Handling, erection	50%	of purchased equip cost (B)	75,625
Electrical	8%	of purchased equip cost (B)	12,100
Piping	1%	of purchased equip cost (B)	1,513
Insulation	7%	of purchased equip cost (B)	10,588
Painting	4%	of purchased equip cost (B)	6,050
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**111,925**
Total Direct Capital Cost			**263,175**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	15,125
Construction, field exp.	20%	of purchased equip cost (B)	30,250
Construction fee	10%	of purchased equip cost (B)	15,125
Startup	1%	of purchased equip cost (B)	1,513
Tests	1%	of purchased equip cost (B)	1,513
Contingencies	3%	of purchased equip cost (B)	4,538
Total Indirect Capital Costs	45%		**68,063**
Total Capital Investment (TCI)			**331,238**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**331,238**
Total Annualized Capital Costs			**31,266**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.047	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity	82,787
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**175,334**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	3,312
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	3,312
Administration (2% total capital costs)	2%	of total capital costs (TCI)	6,625
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**100,044**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**275,379**
Pollutant Removed (tons/yr)[B]			**44**
Cost per ton of NOx Removed			**6,330**

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	224	kW-hr	1,764,439	82,787	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	52,560	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation						
Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**101.50**	
Emission Reduction T/yr					**44**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	76,579	5	0.55	0.9	90.5	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	brake horse power		kW			
Fan motor	300		224			

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		The cost of the fan + duct	**250,000**
Instrumentation	10%	of control device cost (A)	25,000
Sales Taxes	6.0%	of control device cost (A)	15,000
Freight	5%	of control device cost (A)	12,500
Auxiliary equipment (not included in CD cost)	-	of control device cost (A) - See Notes	0
Purchased Equipment Total (B)	21%		**302,500**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	12,100
Handling, erection	50%	of purchased equip cost (B)	151,250
Electrical	8%	of purchased equip cost (B)	24,200
Piping	1%	of purchased equip cost (B)	3,025
Insulation	7%	of purchased equip cost (B)	21,175
Painting	4%	of purchased equip cost (B)	12,100
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**223,850**
Total Direct Capital Cost			**526,350**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	30,250
Construction, field exp.	20%	of purchased equip cost (B)	60,500
Construction fee	10%	of purchased equip cost (B)	30,250
Startup	1%	of purchased equip cost (B)	3,025
Tests	1%	of purchased equip cost (B)	3,025
Contingencies	3%	of purchased equip cost (B)	9,075
Total Indirect Capital Costs	45%		**136,125**
Total Capital Investment (TCI)			**662,475**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**662,475**
Total Annualized Capital Costs			**62,533**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.047	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity	82,787
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**175,334**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,625
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,625
Administration (2% total capital costs)	2%	of total capital costs (TCI)	13,250
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**144,560**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**319,895**
Pollutant Removed (tons/yr)[B]			**44**
Cost per ton of NOx Removed			**7,354**

BART ANALYSIS 2004
FLUE GAS RECIRCULATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	224	kW-hr	1,764,439	82,787	$/kW-hr, 224 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	52,560	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**101.50**	
Emission Reduction T/yr					**44**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	76,579	5	0.55	0.9	90.5	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	brake horse power		kW			
Fan motor	300		224			

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**42,477**
Instrumentation	10%	of control device cost (A)	4,248
Sales Taxes	6.0%	of control device cost (A)	2,549
Freight	5%	of control device cost (A)	2,124
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	0
Purchased Equipment Total (B)	21%		**51,397**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	2,056
Handling, erection	50%	of purchased equip cost (B)	25,699
Electrical	8%	of purchased equip cost (B)	4,112
Piping	1%	of purchased equip cost (B)	514
Insulation	7%	of purchased equip cost (B)	3,598
Painting	4%	of purchased equip cost (B)	2,056
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**38,034**
Total Direct Capital Cost			**89,431**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	5,140
Construction, field exp.	20%	of purchased equip cost (B)	10,279
Construction fee	10%	of purchased equip cost (B)	5,140
Startup	1%	of purchased equip cost (B)	514
Tests	1%	of purchased equip cost (B)	514
Contingencies	3%	of purchased equip cost (B)	1,542
Total Indirect Capital Costs	45%		**23,129**
Total Capital Investment (TCI)			**112,560**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**112,560**
Total Annualized Capital Costs			**10,625**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,126
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,126
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,251
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**70,655**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**163,202**
Pollutant Removed (tons/yr)			**58**
Cost per ton of NOx Removed			**2,814**

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BART ANALYSIS 2004
LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation: 8,760**			
				Utilization rate:	**90%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,758	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**87.00**	
Emission Reduction T/yr					**58**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			542,291
Instrumentation	10%	of control device cost (A)	54,229
Sales Taxes	6.0%	of control device cost (A)	32,537
Freight	5%	of control device cost (A)	27,115
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	0
Purchased Equipment Total (B)	21%		**656,172**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	26,247
Handling, erection	50%	of purchased equip cost (B)	328,086
Electrical	8%	of purchased equip cost (B)	52,494
Piping	1%	of purchased equip cost (B)	6,562
Insulation	7%	of purchased equip cost (B)	45,932
Painting	4%	of purchased equip cost (B)	26,247
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**485,567**
Total Direct Capital Cost			**1,141,739**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	65,617
Construction, field exp.	20%	of purchased equip cost (B)	131,234
Construction fee	10%	of purchased equip cost (B)	65,617
Startup	1%	of purchased equip cost (B)	6,562
Tests	1%	of purchased equip cost (B)	6,562
Contingencies	3%	of purchased equip cost (B)	19,685
Total Indirect Capital Costs	45%		**295,277**
Total Capital Investment (TCI)			**1,437,016**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**1,437,016**
Total Annualized Capital Costs			**135,644**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**92,547**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	14,370
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	14,370
Administration (2% total capital costs)	2%	of total capital costs (TCI)	28,740
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**248,653**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**341,200**
Pollutant Removed (tons/yr)			**58**
Cost per ton of NOx Removed			**5,883**

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BART ANALYSIS 2004
LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation: 8,760**			
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0	Mscf	100	Mscfm	47,304	0	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	6,758	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				40%	**87.00**	
Emission Reduction T/yr					**58**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**148,122**
Instrumentation	1%	of control device cost (A)	1,481
Sales Taxes	6.0%	of control device cost (A)	8,887
Freight	5%	of control device cost (A)	7,406
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**165,897**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	13,272
Handling, erection	14%	of purchased equip cost (B)	23,226
Electrical	4%	of purchased equip cost (B)	6,636
Piping	4%	of purchased equip cost (B)	6,636
Insulation	1%	of purchased equip cost (B)	1,659
Painting	1%	of purchased equip cost (B)	1,659
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**53,087**
Total Direct Capital Cost			**218,984**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	16,590
Construction, field exp.	5%	of purchased equip cost (B)	8,295
Construction fee	10%	of purchased equip cost (B)	16,590
Startup	2%	of purchased equip cost (B)	3,318
Tests	1%	of purchased equip cost (B)	1,659
Contingencies	3%	of purchased equip cost (B)	4,977
Total Indirect Capital Costs	31%		**51,428**
Total Capital Investment (TCI)			**270,412**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**270,412**
Total Annualized Capital Costs			**25,525**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity	167,392
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity	776
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	60,812
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**265,260**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	2,704
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	2,704
Administration (2% total capital costs)	2%	of total capital costs (TCI)	5,408
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**57,602**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**322,862**
Pollutant Removed (tons/yr)			**44**
Cost per ton of NOx Removed			**7,422**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	452.5	kW-hr	3,567,603	167,392	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	6.0	scfm	2,831,402	776	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.10	Lb	74.8	lb/hr	589,875	60,812	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBTU/	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**101.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**44**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	5	0.55	0.9	452.5	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.13	50	0.8	0.9	0.00	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					452.5	

Ammonia	33.1	lb/hr NOx	0.370	lb NH3/lb NOx	15.7	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	74.8	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			6.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**542,291**
Instrumentation	1%	of control device cost (A)	5,423
Sales Taxes	6.0%	of control device cost (A)	32,537
Freight	5%	of control device cost (A)	27,115
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**607,366**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	48,589
Handling, erection	14%	of purchased equip cost (B)	85,031
Electrical	4%	of purchased equip cost (B)	24,295
Piping	4%	of purchased equip cost (B)	24,295
Insulation	1%	of purchased equip cost (B)	6,074
Painting	1%	of purchased equip cost (B)	6,074
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**194,357**
Total Direct Capital Cost			**801,723**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	60,737
Construction, field exp.	5%	of purchased equip cost (B)	30,368
Construction fee	10%	of purchased equip cost (B)	60,737
Startup	2%	of purchased equip cost (B)	12,147
Tests	1%	of purchased equip cost (B)	6,074
Contingencies	3%	of purchased equip cost (B)	18,221
Total Indirect Capital Costs	31%		**188,283**
Total Capital Investment (TCI)			**990,006**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**990,006**
Total Annualized Capital Costs			**93,450**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity	167,392
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity	776
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	60,812
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**265,260**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	9,900
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	9,900
Administration (2% total capital costs)	2%	of total capital costs (TCI)	19,800
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**154,311**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**419,570**
Pollutant Removed (tons/yr)			**44**
Cost per ton of NOx Removed			**9,645**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	452.5	kW-hr	3,567,603	167,392	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	6.0	scfm	2,831,402	776	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.10	Lb	74.8	lb/hr	589,875	60,812	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBTU/	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				30%	**101.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**44**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	5	0.55	0.9	452.5	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.13	50	0.8	0.9	0.00	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					452.5	

Ammonia	33.1	lb/hr NOx	0.370	lb NH3/lb NOx	15.7	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	74.8	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			6.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**148,122**
Instrumentation	1%	of control device cost (A)	1,481
Sales Taxes	6.0%	of control device cost (A)	8,887
Freight	5%	of control device cost (A)	7,406
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**165,897**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	13,272
Handling, erection	14%	of purchased equip cost (B)	23,226
Electrical	4%	of purchased equip cost (B)	6,636
Piping	4%	of purchased equip cost (B)	6,636
Insulation	1%	of purchased equip cost (B)	1,659
Painting	1%	of purchased equip cost (B)	1,659
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**53,087**
Total Direct Capital Cost			**218,984**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	16,590
Construction, field exp.	5%	of purchased equip cost (B)	8,295
Construction fee	10%	of purchased equip cost (B)	16,590
Startup	2%	of purchased equip cost (B)	3,318
Tests	1%	of purchased equip cost (B)	1,659
Contingencies	3%	of purchased equip cost (B)	4,977
Total Indirect Capital Costs	31%		**51,428**
Total Capital Investment (TCI)			**270,412**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**270,412**
Total Annualized Capital Costs			**25,525**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity	167,392
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity	776
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	60,812
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**265,260**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	2,704
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	2,704
Administration (2% total capital costs)	2%	of total capital costs (TCI)	5,408
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**57,602**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**322,862**
Pollutant Removed (tons/yr)			**73**
Cost per ton of NOx Removed			**4,453**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations					**Utilization Rate**		**90.0%**	
					Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Supervisor	NA				NA	NA	15% of Operator Costs	
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Maint Mtls	NA				NA	NA	of purchased equipment costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.047	kW-hr	452.5	kW-hr	3,567,603	167,392	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	6.0	scfm	2,831,402	776	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity	
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia	
Reagent #2 (Urea 50% Solution)	0.10	Lb	74.8	lb/hr	589,875	60,812	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr	
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr	
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity	
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu		134 MMBTU/	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				50%	**72.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**73**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	5	0.55	0.9	452.5	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.13	50	0.8	0.9	0.00	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					452.5	

Ammonia	33.1	lb/hr NOx	0.370	lb NH3/lb NOx	15.7	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	74.8	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			6.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)		SNCR equipment	**542,291**
Instrumentation	1%	of control device cost (A)	5,423
Sales Taxes	6.0%	of control device cost (A)	32,537
Freight	5%	of control device cost (A)	27,115
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	12.0%		**607,366**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	48,589
Handling, erection	14%	of purchased equip cost (B)	85,031
Electrical	4%	of purchased equip cost (B)	24,295
Piping	4%	of purchased equip cost (B)	24,295
Insulation	1%	of purchased equip cost (B)	6,074
Painting	1%	of purchased equip cost (B)	6,074
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	
Buildings, as required		Building extention to for additional grate sections	
Installation Total	32%		**194,357**
Total Direct Capital Cost			**801,723**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	60,737
Construction, field exp.	5%	of purchased equip cost (B)	30,368
Construction fee	10%	of purchased equip cost (B)	60,737
Startup	2%	of purchased equip cost (B)	12,147
Tests	1%	of purchased equip cost (B)	6,074
Contingencies	3%	of purchased equip cost (B)	18,221
Total Indirect Capital Costs	31%		**188,283**
Total Capital Investment (TCI)			**990,006**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**990,006**
Total Annualized Capital Costs			**93,450**
		1.8256	
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	13,896
Supervisor	15%	of oper labor costs	2,084
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	9,727
Maintenance Materials	100%	of maint labor costs	9,727
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity	167,392
Natural Gas (Fuel)	NA		-
Water	0.22	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity	845
Compressed Air	0.27	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity	776
Reagent #1(Anhydrous Ammonia)	NA		-
Reagent #2 (Urea 50% Solution)	0.10	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity	60,812
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**265,260**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	21,261
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	9,900
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	9,900
Administration (2% total capital costs)	2%	of total capital costs (TCI)	19,800
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**154,311**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**419,570**
Pollutant Removed (tons/yr)			**73**
Cost per ton of NOx Removed			**5,787**

BART ANALYSIS 2004
SELECTIVE NON-CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	548	13,896	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.8	Hr	0.5	hr/8 hr shift	548	9,727	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	452.5	kW-hr	3,567,603	167,392	$/kW-hr, 453 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	8	gpm	3,784	845	$/Mgal, 8.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	6.0	scfm	2,831,402	776	$/Mscf, 6.0 scfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	405	Ton	0.0	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.10	Lb	74.8	lb/hr	589,875	60,812	$/Lb, 74.8 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.,90.0%of capacity
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/2-yr perioc	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBTU/	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				50%	**72.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**73**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	5	0.55	0.9	452.5	OAQPS Cost Cont Manual 5th ed - Eq 3.37
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.13	50	0.8	0.9	0.00	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					452.5	

Ammonia	33.1	lb/hr NOx	0.370	lb NH3/lb NOx	15.7	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	2.260	lb Urea Sol'n/lb NOx	74.8	lb/hr Urea Sol'n per vendor quote
Comp Air	0.08	scfm per lb/hr Urea			6.0	

Density of 50% urea solution	71	lb/ft3
	9.49	lb/gal

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**210,685**
Instrumentation	10%	of control device cost (A)	21,068
Sales Taxes	6.0%	of control device cost (A)	12,641
Freight	5%	of control device cost (A)	10,534
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**254,929**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	20,394
Handling, erection	14%	of purchased equip cost (B)	35,690
Electrical	4%	of purchased equip cost (B)	10,197
Piping	4%	of purchased equip cost (B)	10,197
Insulation	1%	of purchased equip cost (B)	2,549
Painting	1%	of purchased equip cost (B)	2,549
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**81,577**
Total Direct Capital Cost			**336,506**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,493
Construction, field exp.	5%	of purchased equip cost (B)	12,746
Construction fee	10%	of purchased equip cost (B)	25,493
Startup	2%	of purchased equip cost (B)	5,099
Tests	1%	of purchased equip cost (B)	2,549
Contingencies	3%	of purchased equip cost (B)	7,648
Total Indirect Capital Costs	31%		**79,028**
Total Capital Investment (TCI)			**415,534**
Replacement Parts Cost & Installation Labor	1,037,702	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**-622,168**
Total Annualized Capital Costs			**-58,728**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,010,380**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,311
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**-22,972**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**987,408**
Pollutant Removed (tons/yr)			**102**
Cost per ton of NOx Removed			**9,728**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**43.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**102**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		1,755,595
Instrumentation	10% of control device cost (A)	175,559
Sales Taxes	6.0% of control device cost (A)	105,336
Freight	5% of control device cost (A)	87,780
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**2,124,270**
Installation		
Foundations & supports	8% of purchased equip cost (B)	169,942
Handling, erection	14% of purchased equip cost (B)	297,398
Electrical	4% of purchased equip cost (B)	84,971
Piping	4% of purchased equip cost (B)	84,971
Insulation	1% of purchased equip cost (B)	21,243
Painting	1% of purchased equip cost (B)	21,243
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**679,766**
Total Direct Capital Cost		**2,804,036**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	212,427
Construction, field exp.	5% of purchased equip cost (B)	106,213
Construction fee	10% of purchased equip cost (B)	212,427
Startup	2% of purchased equip cost (B)	42,485
Tests	1% of purchased equip cost (B)	21,243
Contingencies	3% of purchased equip cost (B)	63,728
Total Indirect Capital Costs	31%	**658,524**
Total Capital Investment (TCI)		**3,462,560**
Replacement Parts Cost & Installation Labor	1,037,702 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,424,858**
Total Annualized Capital Costs		**228,889**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.38 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15% of oper labor costs	1,876
Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,010,380**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	34,626
Insurance (1% total capital costs)	1% of total capital costs (TCI)	34,626
Administration (2% total capital costs)	2% of total capital costs (TCI)	69,251
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**386,527**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**1,396,907**
Pollutant Removed (tons/yr)		**102**
Cost per ton of NOx Removed		**13,762**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**43.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**102**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**210,685**
Instrumentation	10%	of control device cost (A)	21,068
Sales Taxes	6.0%	of control device cost (A)	12,641
Freight	5%	of control device cost (A)	10,534
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**254,929**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	20,394
Handling, erection	14%	of purchased equip cost (B)	35,690
Electrical	4%	of purchased equip cost (B)	10,197
Piping	4%	of purchased equip cost (B)	10,197
Insulation	1%	of purchased equip cost (B)	2,549
Painting	1%	of purchased equip cost (B)	2,549
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**81,577**
Total Direct Capital Cost			**336,506**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,493
Construction, field exp.	5%	of purchased equip cost (B)	12,746
Construction fee	10%	of purchased equip cost (B)	25,493
Startup	2%	of purchased equip cost (B)	5,099
Tests	1%	of purchased equip cost (B)	2,549
Contingencies	3%	of purchased equip cost (B)	7,648
Total Indirect Capital Costs	31%		**79,028**
Total Capital Investment (TCI)			**415,534**
Replacement Parts Cost & Installation Labor	1,037,702	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**-622,168**
Total Annualized Capital Costs			**-58,728**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,010,380**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,311
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**-22,972**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**987,408**
Pollutant Removed (tons/yr)			**131**
Cost per ton of NOx Removed			**7,566**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**14.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**131**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**1,755,595**
Instrumentation	10%	of control device cost (A)	175,559
Sales Taxes	6.0%	of control device cost (A)	105,336
Freight	5%	of control device cost (A)	87,780
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**2,124,270**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	169,942
Handling, erection	14%	of purchased equip cost (B)	297,398
Electrical	4%	of purchased equip cost (B)	84,971
Piping	4%	of purchased equip cost (B)	84,971
Insulation	1%	of purchased equip cost (B)	21,243
Painting	1%	of purchased equip cost (B)	21,243
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**679,766**
Total Direct Capital Cost			**2,804,036**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	212,427
Construction, field exp.	5%	of purchased equip cost (B)	106,213
Construction fee	10%	of purchased equip cost (B)	212,427
Startup	2%	of purchased equip cost (B)	42,485
Tests	1%	of purchased equip cost (B)	21,243
Contingencies	3%	of purchased equip cost (B)	63,728
Total Indirect Capital Costs	31%		**658,524**
Total Capital Investment (TCI)			**3,462,560**
Replacement Parts Cost & Installation Labor	1,037,702	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,424,858**
Total Annualized Capital Costs			**228,889**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,010,380**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	34,626
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	34,626
Administration (2% total capital costs)	2%	of total capital costs (TCI)	69,251
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**386,527**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**1,396,907**
Pollutant Removed (tons/yr)			**131**
Cost per ton of NOx Removed			**10,704**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**14.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**131**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**166,820**
Instrumentation	10%	of control device cost (A)	16,682
Sales Taxes	6.0%	of control device cost (A)	10,009
Freight	5%	of control device cost (A)	8,341
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**201,853**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	8,074
Handling, erection	50%	of purchased equip cost (B)	100,926
Electrical	8%	of purchased equip cost (B)	16,148
Piping	1%	of purchased equip cost (B)	2,019
Insulation	7%	of purchased equip cost (B)	14,130
Painting	4%	of purchased equip cost (B)	8,074
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**149,371**
Total Direct Capital Cost			**351,224**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	20,185
Construction, field exp.	20%	of purchased equip cost (B)	40,371
Construction fee	10%	of purchased equip cost (B)	20,185
Startup	1%	of purchased equip cost (B)	2,019
Tests	1%	of purchased equip cost (B)	2,019
Contingencies	3%	of purchased equip cost (B)	6,056
Total Indirect Capital Costs	45%		**90,834**
Total Capital Investment (TCI)			**442,057**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**442,057**
Total Annualized Capital Costs			**41,727**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,841
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**114,938**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**219,491**
Pollutant Removed (tons/yr)			**108.8**
Cost per ton of NOx Removed			**2,018**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				75%	**36.25**	
Emission Reduction T/yr					**108.75**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**166,820**
Instrumentation	10%	of control device cost (A)	16,682
Sales Taxes	6.0%	of control device cost (A)	10,009
Freight	5%	of control device cost (A)	8,341
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**201,853**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	8,074
Handling, erection	50%	of purchased equip cost (B)	100,926
Electrical	8%	of purchased equip cost (B)	16,148
Piping	1%	of purchased equip cost (B)	2,019
Insulation	7%	of purchased equip cost (B)	14,130
Painting	4%	of purchased equip cost (B)	8,074
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**149,371**
Total Direct Capital Cost			**351,224**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	20,185
Construction, field exp.	20%	of purchased equip cost (B)	40,371
Construction fee	10%	of purchased equip cost (B)	20,185
Startup	1%	of purchased equip cost (B)	2,019
Tests	1%	of purchased equip cost (B)	2,019
Contingencies	3%	of purchased equip cost (B)	6,056
Total Indirect Capital Costs	45%		**90,834**
Total Capital Investment (TCI)			**442,057**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**442,057**
Total Annualized Capital Costs			**41,727**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,841
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**114,938**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**219,491**
Pollutant Removed (tons/yr)			**123.3**
Cost per ton of NOx Removed			**1,781**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				85%	**21.75**	
Emission Reduction T/yr					**123.25**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**166,820**
Instrumentation	10%	of control device cost (A)	16,682
Sales Taxes	6.0%	of control device cost (A)	10,009
Freight	5%	of control device cost (A)	8,341
Auxiliary equipment (not included in CD cost)	-	of control device cost (A)	
Purchased Equipment Total (B)	21%		**201,853**
Installation			
Foundations & supports	4%	of purchased equip cost (B)	8,074
Handling, erection	50%	of purchased equip cost (B)	100,926
Electrical	8%	of purchased equip cost (B)	16,148
Piping	1%	of purchased equip cost (B)	2,019
Insulation	7%	of purchased equip cost (B)	14,130
Painting	4%	of purchased equip cost (B)	8,074
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	74%		**149,371**
Total Direct Capital Cost			**351,224**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	20,185
Construction, field exp.	20%	of purchased equip cost (B)	40,371
Construction fee	10%	of purchased equip cost (B)	20,185
Startup	1%	of purchased equip cost (B)	2,019
Tests	1%	of purchased equip cost (B)	2,019
Contingencies	3%	of purchased equip cost (B)	6,056
Total Indirect Capital Costs	45%		**90,834**
Total Capital Investment (TCI)			**442,057**
Replacement Parts Cost & Installation Labor	0	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**442,057**
Total Annualized Capital Costs			**41,727**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of oper labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maint labor costs	17,509
Utilities, Reagents, Waste Management & Replacements			
Electricity	NA		-
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,841
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**114,938**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**219,491**
Pollutant Removed (tons/yr)			**108.8**
Cost per ton of NOx Removed			**2,018**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization rate: 90%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
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Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBtu/hı	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				75%	**36.25**	
Emission Reduction T/yr					**108.75**	

	Flow acfm	D P in H2O	Blower Effi	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
ULTRA LOW NOX BURNER

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Water	NA		-
Compressed Air	0.25	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity	12,006
Reagent #1(Caustic)	NA		-
Reagent #2	NA		-
Solid Waste Disposal	NA		-
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	NA		-
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**104,553**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,421
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,841
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**114,938**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**219,491**
Pollutant Removed (tons/yr)			**123.3**
Cost per ton of NOx Removed			**1,781**

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BART ANALYSIS 2004
ULTRA LOW NOX BURNER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization rate:		**90%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	100	Mscfm	47,304	12,006	$/Mscf, 100.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, Ammonia
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	0	Ton	0.857	ton/hr	7,509	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.27	lb/MMBtu	134	MMBtu/hr	NA	**145**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				85%	**21.75**	
Emission Reduction T/yr					**123.25**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	0	5	0.55	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 3.37

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**210,685**
Instrumentation	10%	of control device cost (A)	21,068
Sales Taxes	6.0%	of control device cost (A)	12,641
Freight	5%	of control device cost (A)	10,534
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**254,929**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	20,394
Handling, erection	14%	of purchased equip cost (B)	35,690
Electrical	4%	of purchased equip cost (B)	10,197
Piping	4%	of purchased equip cost (B)	10,197
Insulation	1%	of purchased equip cost (B)	2,549
Painting	1%	of purchased equip cost (B)	2,549
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**81,577**
Total Direct Capital Cost			**336,506**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,493
Construction, field exp.	5%	of purchased equip cost (B)	12,746
Construction fee	10%	of purchased equip cost (B)	25,493
Startup	2%	of purchased equip cost (B)	5,099
Tests	1%	of purchased equip cost (B)	2,549
Contingencies	3%	of purchased equip cost (B)	7,648
Total Indirect Capital Costs	31%		**79,028**
Total Capital Investment (TCI)			**415,534**
Replacement Parts Cost & Installation Labor	1,037,702	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**-622,168**
Total Annualized Capital Costs			**-58,728**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,010,380**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,311
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**-22,972**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**987,408**
Pollutant Removed (tons/yr)			**102**
Cost per ton of NOx Removed			**9,728**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**43.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**102**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**1,755,595**
Instrumentation	10%	of control device cost (A)	175,559
Sales Taxes	6.0%	of control device cost (A)	105,336
Freight	5%	of control device cost (A)	87,780
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**2,124,270**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	169,942
Handling, erection	14%	of purchased equip cost (B)	297,398
Electrical	4%	of purchased equip cost (B)	84,971
Piping	4%	of purchased equip cost (B)	84,971
Insulation	1%	of purchased equip cost (B)	21,243
Painting	1%	of purchased equip cost (B)	21,243
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**679,766**
Total Direct Capital Cost			**2,804,036**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	212,427
Construction, field exp.	5%	of purchased equip cost (B)	106,213
Construction fee	10%	of purchased equip cost (B)	212,427
Startup	2%	of purchased equip cost (B)	42,485
Tests	1%	of purchased equip cost (B)	21,243
Contingencies	3%	of purchased equip cost (B)	63,728
Total Indirect Capital Costs	31%		**658,524**
Total Capital Investment (TCI)			**3,462,560**
Replacement Parts Cost & Installation Labor	1,037,702	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**2,424,858**
Total Annualized Capital Costs			**228,889**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,010,380**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	34,626
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	34,626
Administration (2% total capital costs)	2%	of total capital costs (TCI)	69,251
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**386,527**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**1,396,907**
Pollutant Removed (tons/yr)			**102**
Cost per ton of NOx Removed			**13,762**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				70%	**43.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**102**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required		
Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS		
Direct Capital Costs		
Purchased Equipment (1)		
Control Device (A)		**210,685**
Instrumentation	10% of control device cost (A)	21,068
Sales Taxes	6.0% of control device cost (A)	12,641
Freight	5% of control device cost (A)	10,534
Auxiliary equipment (not included in CD cost)	0% of control device cost (A)	0
Purchased Equipment Total (B)	21.0%	**254,929**
Installation		
Foundations & supports	8% of purchased equip cost (B)	20,394
Handling, erection	14% of purchased equip cost (B)	35,690
Electrical	4% of purchased equip cost (B)	10,197
Piping	4% of purchased equip cost (B)	10,197
Insulation	1% of purchased equip cost (B)	2,549
Painting	1% of purchased equip cost (B)	2,549
Expenses not covered by items listed above	0% of purchased equip cost (B)	0
Site Preparation, as required	Site Specific	NA
Buildings, as required	Site Specific	NA
Installation Total	32%	**81,577**
Total Direct Capital Cost		**336,506**
Indirect Capital Costs		
Engineering, supervision	10% of purchased equip cost (B)	25,493
Construction, field exp.	5% of purchased equip cost (B)	12,746
Construction fee	10% of purchased equip cost (B)	25,493
Startup	2% of purchased equip cost (B)	5,099
Tests	1% of purchased equip cost (B)	2,549
Contingencies	3% of purchased equip cost (B)	7,648
Total Indirect Capital Costs	31%	**79,028**
Total Capital Investment (TCI)		**415,534**
Replacement Parts Cost & Installation Labor	1,037,702 Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**-622,168**
Total Annualized Capital Costs		**-58,728**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor	25.38 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15% of oper labor costs	1,876
Maintenance Labor	17.77 $/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100% of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.05 $/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA	-
Water	NA	-
Compressed Air	NA	-
Reagent #1(Anhydrous Ammonia)	411.17 $/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA	-
Solid Waste Disposal	25.38 $/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA	-
Wastewater Treatment	NA	-
Catalyst	159.11 $/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA	-
Total Annual Direct Operating Costs		**1,010,380**
Indirect Operating Costs		
Overhead	60% of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1% of total capital costs (TCI)	4,155
Insurance (1% total capital costs)	1% of total capital costs (TCI)	4,155
Administration (2% total capital costs)	2% of total capital costs (TCI)	8,311
Total Indirect Operating Costs	Sum indirect oper costs + capital recovery cost	**-22,972**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)		**987,408**
Pollutant Removed (tons/yr)		**131**
Cost per ton of NOx Removed		**7,566**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**14.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**131**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Control Device (A)			**210,685**
Instrumentation	10%	of control device cost (A)	21,068
Sales Taxes	6.0%	of control device cost (A)	12,641
Freight	5%	of control device cost (A)	10,534
Auxiliary equipment (not included in CD cost)	0%	of control device cost (A)	0
Purchased Equipment Total (B)	21.0%		**254,929**
Installation			
Foundations & supports	8%	of purchased equip cost (B)	20,394
Handling, erection	14%	of purchased equip cost (B)	35,690
Electrical	4%	of purchased equip cost (B)	10,197
Piping	4%	of purchased equip cost (B)	10,197
Insulation	1%	of purchased equip cost (B)	2,549
Painting	1%	of purchased equip cost (B)	2,549
Expenses not covered by items listed above	0%	of purchased equip cost (B)	0
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Installation Total	32%		**81,577**
Total Direct Capital Cost			**336,506**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,493
Construction, field exp.	5%	of purchased equip cost (B)	12,746
Construction fee	10%	of purchased equip cost (B)	25,493
Startup	2%	of purchased equip cost (B)	5,099
Tests	1%	of purchased equip cost (B)	2,549
Contingencies	3%	of purchased equip cost (B)	7,648
Total Indirect Capital Costs	31%		**79,028**
Total Capital Investment (TCI)			**415,534**
Replacement Parts Cost & Installation Labor	1,037,702	Capital Recovery Costs, Equipment Life 20 years, Interest Rate, 7%	**-622,168**
Total Annualized Capital Costs			**-58,728**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs	1,876
Maintenance Labor	17.77	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	8,754
Maintenance Materials	100%	of maint labor costs	8,754
Utilities, Reagents, Waste Management & Replacements			
Electricity	0.05	$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity	381,652
Natural Gas (Fuel)	NA		-
Water	NA		-
Compressed Air	NA		-
Reagent #1(Anhydrous Ammonia)	411.17	$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia	21,587
Reagent #2 (Urea 50% Solution)	NA		-
Solid Waste Disposal	25.38	$/Ton, 51.4 ton/yr	1,305
Hazardous Waste Disposal	NA		-
Wastewater Treatment	NA		-
Catalyst	159.11	$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity	573,945
Replacement Parts	NA		-
Total Annual Direct Operating Costs			**1,010,380**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	19,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	4,155
Administration (2% total capital costs)	2%	of total capital costs (TCI)	8,311
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**-22,972**
Total Annual Cost (Annualized Capital Cost + Operating Cost) (SCR)			**987,408**
Pollutant Removed (tons/yr)			**131**
Cost per ton of NOx Removed			**7,566**

BART ANALYSIS 2004
SELECTIVE CATALYTIC REDUCTION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost					
Catalyst Life	2	years	Catalyst Disposal Amount in Tons/yr at 35 lb/ft^3		
CRF	0.5531		Amount	Yrs Service	T/yr Waste
Catalyst cost per unit	159.11	\$/ft^3	102.8	2	51.4
Amount Required	5875.7	ft^3			
Catalyst Cost	1,037,702	Cost adjusted for freight & sales tax			
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)			
Total Installed Cost	**1,037,702**				
Annualized Cost	**573,945**				

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	\$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **1,037,702**

Design Flow	109,000	dscfm	123,864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Utilization Rate**		**90.0%**	
				Annual hours of operation:		**8,760**	
Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	8,754	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1031.7	kW-hr	8,134,107	381,652	\$/kW-hr, 1,032 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	\$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Anhydrous Ammonia)	411.17	Ton	14.5	lb/hr	105,005	21,587	\$/Ton, 14.5 lb/hr, 8760 hr/yr, Ammonia
Reagent #2 (Urea 50% Solution)	0.085	Lb	0.0	lb/hr	0	0	\$/Lb, 0.0 lb/hr, 8760 hr/yr, 50 wt% Urea Soln.
SW Disposal	25.38	Ton	51.4	ton/yr	51	1,305	\$/Ton, 51.4 ton/yr
Haz W Disp	273	Ton	0.000	ton/2-yr period	0.00	0	\$/Ton, 0.275 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	159.11	ft^3	5875.7	ft^3	2	573,945	\$/ft3, 5,875.7 ft3, 2, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	\$/bag	0	bags	2	0	\$/\$/bag, 0.0 bags, 2, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Rate Hrs**	**% Max Capacity**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.275	lb/MMBtu	134	MMBTU/HR	NA	145	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**14.50**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**131**	

	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW	
Blower	382,893	11.4	0.55	0.9	1031.7	OAQPS Cost Cont Manual 5th ed - Eq 3.37
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Reagent Pump	0.02	50	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Total Electricity					**1031.7**	

Ammonia	29.8	lb/hr NOx	0.370	lb NH3/lb NOx	14.5	lb/hr NH3; inlcudes 3.5 lb/hr for NH3 slip
Urea 50% Sol'n	33.1	lb/hr NOx	1.317	lb Urea Sol'n/lb NOx	56.1	lb/hr Urea Sol'n; inlcudes 12.5 lb/hr for NH3 slip

Estimating amount of catalyst required

Vol. #1	5513	ft3
Flow #1	359256	acfm
Flow #2	382,893	
Vol #2	**5875.7**	ft3

SO_x Boilers

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**1,030,184**
Instrumentation	10%	of control device cost (A)	103,018
Sales Taxes	6.0%	of control device cost (A)	61,811
Freight	5%	of control device cost (A)	51,509
Purchased Equipment Total (B	21%		**1,246,523**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	149,583
Handling & erection	40%	of purchased equip cost (B)	498,609
Electrical	1%	of purchased equip cost (B)	12,465
Piping	30%	of purchased equip cost (B)	373,957
Insulation	1%	of purchased equip cost (B)	12,465
Painting	1%	of purchased equip cost (B)	12,465
Installation Total	85%		**1,059,544**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**2,306,067**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	124,652
Construction & field expenses	10%	of purchased equip cost (B)	124,652
Construction fee	10%	of purchased equip cost (B)	124,652
Start-up	1%	of purchased equip cost (B)	12,465
Performance test	1%	of purchased equip cost (B)	12,465
Contingencies	3%	of purchased equip cost (B)	37,396
Total Indirect Capital Costs, IC	35%		**436,283**
Total Capital Investment (TCI) = DC + IC			**2,742,350**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	328,034
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity	617,249
Total Annual Direct Operating Costs			**979,119**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	54,847
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	390,449
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**1,499,564**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**2,478,683**
Pollutant Removed (tons/yr)[B]			**570**
Cost per ton of SO2 Removed			**4,351**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations **Annual hours of operation:** **8,760**
Utilization Rate: **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1668.6	kW-hr	13,155,339	617,249	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1.5	gpm	717	146	$/Mgal, 1.5 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	245.90	lb/hr	1,077	328,034	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.195	ton/hr	1,539	39,063	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	

Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%**.
				90%	**63**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**569.7**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	2	125	0.8	0.7	0.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Lime Use	144.53	lb/hr SO2	1.7	lb Lime/lb SO2	245.90	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Reagent Feed rate	245.90	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	1.67	gpm	Equation 6-39 EPA/600/R-00/093
water use	1.52	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	328,034
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity	617,249
Total Annual Direct Operating Costs			**979,119**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**19,763,732**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**20,742,851**
Pollutant Removed (tons/yr)[B]			**570**
Cost per ton of SO2 Removed			**36,408**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1668.6	kW-hr	13,155,339	617,249	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1.5	gpm	717	146	$/Mgal, 1.5 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	245.90	lb/hr	1,077	328,034	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.195	ton/hr	1,539	39,063	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculatio

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
Uncontrolled Emission Rate						
0.25	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**T/yr**	**Currently assumes 80%**.
				90%	**63**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**569.7**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	2	125	0.8	0.7	0.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Lime Use	144.53	lb/hr SO2	1.7	lb Lime/lb SO2	245.90	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Reagent Feed rate	245.90	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	1.67	gpm	Equation 6-39 EPA/600/R-00/093
water use	1.52	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	328,034
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity	617,249
Total Annual Direct Operating Costs			**979,119**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**19,763,732**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**20,742,851**
Pollutant Removed (tons/yr)[B]			**601**
Cost per ton of SO2 Removed			**34,492**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cos		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1668.6	kW-hr	13,155,339	617,249	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1.5	gpm	717	146	$/Mgal, 1.5 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	245.90	lb/hr	1,077	328,034	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.195	ton/hr	1,539	39,063	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculatio

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	
Controlled Emission Rate						
Perf Guarantee	**Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	
				95%		**Currently assumes 80%**.
				95%	**32**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**601.4**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	2	125	0.8	0.7	0.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53 lb/hr SO2	2.50 lb NaOH/lb SO2	361.32	lb/hr Caustic
Lime Use	144.53 lb/hr SO2	1.7 lb Lime/lb SO2	245.90	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Reagent Feed rate	245.90	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	1.67	gpm	Equation 6-39 EPA/600/R-00/093
water use	1.52	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**1,030,184**
Instrumentation	10%	of control device cost (A)	103,018
Sales Taxes	6.0%	of control device cost (A)	61,811
Freight	5%	of control device cost (A)	51,509
Purchased Equipment Total (B	21%		**1,246,523**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	149,583
Handling & erection	40%	of purchased equip cost (B)	498,609
Electrical	1%	of purchased equip cost (B)	12,465
Piping	30%	of purchased equip cost (B)	373,957
Insulation	1%	of purchased equip cost (B)	12,465
Painting	1%	of purchased equip cost (B)	12,465
Installation Total	85%		**1,059,544**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**2,306,067**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	124,652
Construction & field expenses	10%	of purchased equip cost (B)	124,652
Construction fee	10%	of purchased equip cost (B)	124,652
Start-up	1%	of purchased equip cost (B)	12,465
Performance test	1%	of purchased equip cost (B)	12,465
Contingencies	3%	of purchased equip cost (B)	37,396
Total Indirect Capital Costs, IC	35%		**436,283**
Total Capital Investment (TCI) = DC + IC			**2,742,350**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	328,034
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity	617,249
Total Annual Direct Operating Costs			**979,119**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	54,847
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	390,449
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**1,499,564**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**2,478,683**
Pollutant Removed (tons/yr)[B]			**601**
Cost per ton of SO2 Removed			**4,122**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1668.6	kW-hr	13,155,339	617,249	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1.5	gpm	717	146	$/Mgal, 1.5 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	245.90	lb/hr	1,077	328,034	$/Ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.195	ton/hr	1,539	39,063	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
Uncontrolled Emission Rate						
0.25	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
Controlled Emission Rate				95%		**Currently assumes 80%**.
				95%	**32**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**601.4**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	2	125	0.8	0.7	0.1	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Lime Use	144.53	lb/hr SO2	1.7	lb Lime/lb SO2	245.90	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Reagent Feed rate	245.90	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	1.67	gpm	Equation 6-39 EPA/600/R-00/093
water use	1.52	gpm	

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**597,758**
Instrumentation	10%	of control device cost (A)	59,776
Sales Taxes	6%	of control device cost (A)	35,866
Freight	5%	of control device cost (A)	29,888
Purchased Equipment Total (B)	21%		**723,288**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	28,932
Handling & erection	50%	of purchased equip cost (B)	361,644
Electrical	8%	of purchased equip cost (B)	57,863
Piping	1%	of purchased equip cost (B)	7,233
Insulation for ductwork	7%	of purchased equip cost (B)	50,630
Painting	4%	of purchased equip cost (B)	28,932
Installation Total	74%	0	**535,233**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**1,258,521**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	72,329
Construction and field expense	20%	of purchased equip cost (B)	144,658
Contractor fees	10%	of purchased equip cost (B)	72,329
Startup	1%	of purchased equip cost (B)	7,233
Performance test	1%	of purchased equip cost (B)	7,233
Contingencies	3%	of purchased equip cost (B)	21,699
Total Indirect Capital Costs	45%		**325,479**
Total Capital Investment (TCI) = DC + IC			**1,584,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			344,907
Utilities			
Electricity	0.05	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity	1,789,068
Compressed Air	0.27	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity	131,839
Solid Waste Disposal	25.38	$/Ton, 390.430 lb/hr, 8760 hr/yr	37,110
Total Annual Direct Operating Costs (DC			**2,395,471**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	31,680
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	15,840
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	15,840
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	149,518
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**268,407**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**2,663,877**
Pollutant Removed (tons/yr			**1,625**
Cost per ton of PM Removed			**1,640**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	8134	Number
Total Rep Parts Cost	320,821	Cost adjusted for freight & sales tax
Installation Labor	24,086	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**344,907**	
Annualized Cost	**190,765**	

Total Cost Replacement Parts (Bags) **344,907**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	4836	kW-hr	38,130,185	1,789,068	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1016.76	Mscfm	480,968	131,839	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.185	ton/hr	1,462	37,110	$/Ton, 390.430 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 390.430 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	8134.078212	bags	2 yr life	190,765	$/bag, 8,134.1 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatioı

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
390	lb/hr	-	MMBtu/hr	NA	**1710**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**85.5**	Currently assumes 95%.
Emission Reduction T/yı					**1,625**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	508,380	6	0.65	4836.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**7,471,980**
Instrumentation	10%	of control device cost (A)	747,198
Sales Taxes	6%	of control device cost (A)	448,319
Freight	5%	of control device cost (A)	373,599
Purchased Equipment Total (B)	21%		**9,041,096**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	361,644
Handling & erection	50%	of purchased equip cost (B)	4,520,548
Electrical	8%	of purchased equip cost (B)	723,288
Piping	1%	of purchased equip cost (B)	90,411
Insulation for ductwork	7%	of purchased equip cost (B)	632,877
Painting	4%	of purchased equip cost (B)	361,644
Installation Total	74%	0	**6,690,411**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**15,731,507**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	904,110
Construction and field expense	20%	of purchased equip cost (B)	1,808,219
Contractor fees	10%	of purchased equip cost (B)	904,110
Startup	1%	of purchased equip cost (B)	90,411
Performance test	1%	of purchased equip cost (B)	90,411
Contingencies	3%	of purchased equip cost (B)	271,233
Total Indirect Capital Costs	45%		**4,068,493**
Total Capital Investment (TCI) = DC + IC			**19,800,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			344,907
Utilities			
Electricity	0.05	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity	1,789,068
Compressed Air	0.27	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity	131,839
Solid Waste Disposal	25.38	$/Ton, 390.430 lb/hr, 8760 hr/yr	39,059
Total Annual Direct Operating Costs (DC			**2,397,420**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,000
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,000
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,000
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,868,980
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,716,508**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**5,113,928**
Pollutant Removed (tons/yr			**1,710**
Cost per ton of PM Removed			**2,991**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	8134	Number
Total Rep Parts Cost	320,821	Cost adjusted for freight & sales tax
Installation Labor	24,086	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**344,907**	
Annualized Cost	**190,765**	

Total Cost Replacement Parts (Bags) **344,907**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	4836	kW-hr	38,130,185	1,789,068	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1016.76	Mscfm	480,968	131,839	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.195	ton/hr	1,539	39,059	$/Ton, 390.430 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 390.430 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	8134.078212	bags	2 yr life	190,765	$/bag, 8,134.1 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatio

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
390	lb/hr	-	MMBtu/hr	NA	**1710**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.2**	Currently assumes 95%.
Emission Reduction T/yı					**1,710**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	508,380	6	0.65	4836.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**2,575,826**
Instrumentation	10%	of control device cost (A)	257,583
Sales Taxes	6.0%	of control device cost (A)	154,550
Freight	5%	of control device cost (A)	128,791
Purchased Equipment Total (B)	21%		**3,116,750**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	374,010
Handling & erection	40%	of purchased equip cost (B)	1,246,700
Electrical	1%	of purchased equip cost (B)	31,168
Piping	30%	of purchased equip cost (B)	935,025
Insulation	1%	of purchased equip cost (B)	31,168
Painting	1%	of purchased equip cost (B)	31,168
Installation Total	85%		**2,649,238**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**5,765,988**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	311,675
Construction & field expenses	10%	of purchased equip cost (B)	311,675
Construction fee	10%	of purchased equip cost (B)	311,675
Start-up	1%	of purchased equip cost (B)	31,168
Performance test	1%	of purchased equip cost (B)	31,168
Contingencies	3%	of purchased equip cost (B)	93,503
Total Indirect Capital Costs, IC	35%		**1,090,863**
Total Capital Investment (TCI) = DC + IC			**6,856,850**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	404,888
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity	659,195
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity	695,348
Total Annual Direct Operating Costs			**1,793,267**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	137,137
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	976,261
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,064,104**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,857,371**
Pollutant Removed (tons/yr)[B]			**570**
Cost per ton of SO2 Removed			**8,526**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1879.7	kW-hr	14,819,855	695,348	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	915.1	gpm	432,871	87,893	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	361.32	lb/hr	1,424	404,888	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	915.1	gpm	432,871	659,195	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**63**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**569.7**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	915.1	62.5	0.8	0.7	19.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53 lb/hr SO2	2.50 lb NaOH/lb SO2	361.32 lb/hr Caustic
Lime Use	144.53 lb/hr SO2	1.53 lb Lime/lb SO2	221.13 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B)	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	404,888
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity	659,195
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity	695,348
Total Annual Direct Operating Costs			**1,793,267**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**20,577,879**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**22,371,146**
Pollutant Removed (tons/yr)[B]			**570**
Cost per ton of SO2 Removed			**39,266**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1879.7	kW-hr	14,819,855	695,348	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	915.1	gpm	432,871	87,893	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	361.32	lb/hr	1,424	404,888	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	915.1	gpm	432,871	659,195	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.25	lb/MMBtu	650	MMBTU/HR	NA	633.04	

Controlled Emission Rate

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Currently assumes 80%.
				90%		
				90%	63	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					569.7	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	915.1	62.5	0.8	0.7	19.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53 lb/hr SO2	2.50	lb NaOH/lb SO2	361.32 lb/hr Caustic
Lime Use	144.53 lb/hr SO2	1.53	lb Lime/lb SO2	221.13 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**2,575,826**
Instrumentation	10%	of control device cost (A)	257,583
Sales Taxes	6.0%	of control device cost (A)	154,550
Freight	5%	of control device cost (A)	128,791
Purchased Equipment Total (B)	21%		**3,116,750**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	374,010
Handling & erection	40%	of purchased equip cost (B)	1,246,700
Electrical	1%	of purchased equip cost (B)	31,168
Piping	30%	of purchased equip cost (B)	935,025
Insulation	1%	of purchased equip cost (B)	31,168
Painting	1%	of purchased equip cost (B)	31,168
Installation Total	85%		**2,649,238**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**5,765,988**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	311,675
Construction & field expenses	10%	of purchased equip cost (B)	311,675
Construction fee	10%	of purchased equip cost (B)	311,675
Start-up	1%	of purchased equip cost (B)	31,168
Performance test	1%	of purchased equip cost (B)	31,168
Contingencies	3%	of purchased equip cost (B)	93,503
Total Indirect Capital Costs, IC	35%		**1,090,863**
Total Capital Investment (TCI) = DC + IC			**6,856,850**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	404,888
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity	659,195
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity	695,348
Total Annual Direct Operating Costs			**1,793,267**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	137,137
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	976,261
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**3,064,104**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,857,371**
Pollutant Removed (tons/yr)[B]			**633**
Cost per ton of SO2 Removed			**7,674**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1879.7	kW-hr	14,819,855	695,348	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	915.1	gpm	432,871	87,893	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	361.32	lb/hr	1,424	404,888	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	915.1	gpm	432,871	659,195	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	650	MMBTU/HR	NA	633.04	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.99%		
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**633.0**	Assuming 99.99% control.

	Flow acfm	ΔP in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	915.1	62.5	0.8	0.7	19.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Lime Use	144.53	lb/hr SO2	1.53	lb Lime/lb SO2	221.13	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B)	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	404,888
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity	659,195
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity	695,348
Total Annual Direct Operating Costs			**1,793,267**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**20,577,879**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**22,371,146**
Pollutant Removed (tons/yr)[B]			**633**
Cost per ton of SO2 Removed			**35,343**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1879.7	kW-hr	14,819,855	695,348	$/kW-hr, 1,880 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	915.1	gpm	432,871	87,893	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	361.32	lb/hr	1,424	404,888	$/Ton, 361.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	915.1	gpm	432,871	659,195	$/Mgal, 915.1 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	650	MMBTU/HR	NA	633.04	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.99%		
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**633.0**	Assuming 99.99% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	915.1	62.5	0.8	0.7	19.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53 lb/hr SO2	2.50	lb NaOH/lb SO2	361.32 lb/hr Caustic
Lime Use	144.53 lb/hr SO2	1.53	lb Lime/lb SO2	221.13 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			7,441,059
Instrumentation	10%	of control device cost (A)	744,106
Sales Taxes	6.0%	of control device cost (A)	446,464
Freight	5%	of control device cost (A)	372,053
Purchased Equipment Total (B)	21%		**9,003,682**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,080,442
Handling & erection	40%	of purchased equip cost (B)	3,601,473
Electrical	1%	of purchased equip cost (B)	90,037
Piping	30%	of purchased equip cost (B)	2,701,105
Insulation	1%	of purchased equip cost (B)	90,037
Painting	1%	of purchased equip cost (B)	90,037
Installation Total	85%		**7,653,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**16,656,811**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	900,368
Construction & field expenses	10%	of purchased equip cost (B)	900,368
Construction fee	10%	of purchased equip cost (B)	900,368
Start-up	1%	of purchased equip cost (B)	90,037
Performance test	1%	of purchased equip cost (B)	90,037
Contingencies	3%	of purchased equip cost (B)	270,110
Total Indirect Capital Costs, IC	35%		**3,151,289**
Total Capital Investment (TCI) = DC + IC			**19,808,100**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	301,256
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity	699,279
Total Annual Direct Operating Costs			**1,034,372**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,162
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	2,820,228
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**4,667,225**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,701,597**
Pollutant Removed (tons/yr)[B]			**601**
Cost per ton of SO2 Removed			**9,481**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1890.4	kW-hr	14,903,649	699,279	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	2.2	gpm	1,035	210	$/Mgal, 2.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	225.83	lb/hr	989	301,256	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%		**Currently assumes 80%.**
				95%	**32**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**601.4**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Limestone Use	144.53	lb/hr SO2	1.6	lb Limestone/lb SO2	225.83	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Limestone Feed rate	225.83	lb/hr	
gypsum formation rate	388	lb/hr	dry basis
gypsum formed	466	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	2	gpm	

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**24,238,993**
Instrumentation	10%	of control device cost (A)	2,423,899
Sales Taxes	6.0%	of control device cost (A)	1,454,340
Freight	5%	of control device cost (A)	1,211,950
Purchased Equipment Total (B)	21%		**29,329,182**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,519,502
Handling & erection	40%	of purchased equip cost (B)	11,731,673
Electrical	1%	of purchased equip cost (B)	293,292
Piping	30%	of purchased equip cost (B)	8,798,755
Insulation	1%	of purchased equip cost (B)	293,292
Painting	1%	of purchased equip cost (B)	293,292
Installation Total	85%		**24,929,805**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**54,258,986**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,932,918
Construction & field expenses	10%	of purchased equip cost (B)	2,932,918
Construction fee	10%	of purchased equip cost (B)	2,932,918
Start-up	1%	of purchased equip cost (B)	293,292
Performance test	1%	of purchased equip cost (B)	293,292
Contingencies	3%	of purchased equip cost (B)	879,875
Total Indirect Capital Costs, IC	35%		**10,265,214**
Total Capital Investment (TCI) = DC + IC			**64,524,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	301,256
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity	699,279
Total Annual Direct Operating Costs			**1,034,372**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,290,484
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	9,186,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**12,822,436**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,856,808**
Pollutant Removed (tons/yr)[B]			**601**
Cost per ton of SO2 Removed			**23,041**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1890.4	kW-hr	14,903,649	699,279	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	2.2	gpm	1,035	210	$/Mgal, 2.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	225.83	lb/hr	989	301,256	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				95%	**32**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**601.4**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Limestone Use	144.53	lb/hr SO2	1.6	lb Limestone/lb SO2	225.83	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Limestone Feed rate	225.83	lb/hr	
gypsum formation rate	388	lb/hr	dry basis
gypsum formed	466	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	2	gpm	

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			7,441,059
Instrumentation	10%	of control device cost (A)	744,106
Sales Taxes	6.0%	of control device cost (A)	446,464
Freight	5%	of control device cost (A)	372,053
Purchased Equipment Total (B)	21%		**9,003,682**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,080,442
Handling & erection	40%	of purchased equip cost (B)	3,601,473
Electrical	1%	of purchased equip cost (B)	90,037
Piping	30%	of purchased equip cost (B)	2,701,105
Insulation	1%	of purchased equip cost (B)	90,037
Painting	1%	of purchased equip cost (B)	90,037
Installation Total	85%		**7,653,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**16,656,811**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	900,368
Construction & field expenses	10%	of purchased equip cost (B)	900,368
Construction fee	10%	of purchased equip cost (B)	900,368
Start-up	1%	of purchased equip cost (B)	90,037
Performance test	1%	of purchased equip cost (B)	90,037
Contingencies	3%	of purchased equip cost (B)	270,110
Total Indirect Capital Costs, IC	35%		**3,151,289**
Total Capital Investment (TCI) = DC + IC			**19,808,100**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	301,256
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity	699,279
Total Annual Direct Operating Costs			**1,034,372**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,162
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	2,820,228
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**4,667,225**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,701,597**
Pollutant Removed (tons/yr)[B]			**630**
Cost per ton of SO2 Removed			**9,052**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1890.4	kW-hr	14,903,649	699,279	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	2.2	gpm	1,035	210	$/Mgal, 2.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	225.83	lb/hr	989	301,256	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.50%	**3**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**629.9**	Assuming 99.5% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32	lb/hr Caustic
Limestone Use	144.53	lb/hr SO2	1.6	lb Limestone/lb SO2	225.83	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr		
Limestone Feed rate	225.83	lb/hr		
gypsum formation rate	388	lb/hr	dry basis	
gypsum formed	466	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	2	gpm		

Centrifuge
horse power 40 30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**24,238,993**
Instrumentation	10%	of control device cost (A)	2,423,899
Sales Taxes	6.0%	of control device cost (A)	1,454,340
Freight	5%	of control device cost (A)	1,211,950
Purchased Equipment Total (B)	21%		**29,329,182**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,519,502
Handling & erection	40%	of purchased equip cost (B)	11,731,673
Electrical	1%	of purchased equip cost (B)	293,292
Piping	30%	of purchased equip cost (B)	8,798,755
Insulation	1%	of purchased equip cost (B)	293,292
Painting	1%	of purchased equip cost (B)	293,292
Installation Total	85%		**24,929,805**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**54,258,986**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,932,918
Construction & field expenses	10%	of purchased equip cost (B)	2,932,918
Construction fee	10%	of purchased equip cost (B)	2,932,918
Start-up	1%	of purchased equip cost (B)	293,292
Performance test	1%	of purchased equip cost (B)	293,292
Contingencies	3%	of purchased equip cost (B)	879,875
Total Indirect Capital Costs, IC	35%		**10,265,214**
Total Capital Investment (TCI) = DC + IC			**64,524,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	301,256
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity	699,279
Total Annual Direct Operating Costs			**1,034,372**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,290,484
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	9,186,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**12,822,436**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**13,856,808**
Pollutant Removed (tons/yr)[B]			**630**
Cost per ton of SO2 Removed			**21,999**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1890.4	kW-hr	14,903,649	699,279	$/kW-hr, 1,890 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	2.2	gpm	1,035	210	$/Mgal, 2.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	225.83	lb/hr	989	301,256	$/Ton, 225.8 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
Uncontrolled Emission Rate						
0.2	lb/MMBtu	650	MMBTU/HR	NA	**633.04**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**T/yr**	**Currently assumes 80%.**
				99.50%	**3**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**629.9**	Assuming 99.5% control.

	Flow acfm	ΔP in H2O	Blower Eff	Motor Eff	kW	
Blower	457,542	12	0.55	0.7	1668.5	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4,575	125	0.8	0.7	192.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	144.53	lb/hr SO2	2.50	lb NaOH/lb SO2	361.32 lb/hr Caustic
Limestone Use	144.53	lb/hr SO2	1.6	lb Limestone/lb SO2	225.83 lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	144.53	lb/hr	
Limestone Feed rate	225.83	lb/hr	
gypsum formation rate	388	lb/hr	dry basis
gypsum formed	466	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	2	gpm	

Centrifuge
horse power 40 30 kW

SO_x Furnaces

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**212,376**
Instrumentation	10%	of control device cost (A)	21,238
Sales Taxes	6.0%	of control device cost (A)	12,743
Freight	5%	of control device cost (A)	10,619
Purchased Equipment Total (B	21%		**256,975**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	30,837
Handling & erection	40%	of purchased equip cost (B)	102,790
Electrical	1%	of purchased equip cost (B)	2,570
Piping	30%	of purchased equip cost (B)	77,093
Insulation	1%	of purchased equip cost (B)	2,570
Painting	1%	of purchased equip cost (B)	2,570
Installation Total	85%		**218,429**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**475,405**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,698
Construction & field expenses	10%	of purchased equip cost (B)	25,698
Construction fee	10%	of purchased equip cost (B)	25,698
Start-up	1%	of purchased equip cost (B)	2,570
Performance test	1%	of purchased equip cost (B)	2,570
Contingencies	3%	of purchased equip cost (B)	7,709
Total Indirect Capital Costs, IC	35%		**89,941**
Total Capital Investment (TCI) = DC + IC			**565,346**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	67,625
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity	464,875
Total Annual Direct Operating Costs			**566,337**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	11,307
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,653
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,653
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	80,493
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**689,745**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**1,256,082**
Pollutant Removed (tons/yr)[B]			**117**
Cost per ton of SO2 Removed			**10,694**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations | **Annual hours of operation:** **8,760** | **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1256.7	kW-hr	9,907,820	464,875	$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.3	gpm	148	30	$/Mgal, 0.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	50.69	lb/hr	222	67,625	$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.040	ton/hr	317	8,053	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	134	MMBTU/HR	NA	**130.50**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%**.
				90%	**13**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**117.5**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	0	125	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	29.80	lb/hr SO2	2.50	lb NaOH/lb SO2	74.49	lb/hr Caustic
Lime Use	29.80	lb/hr SO2	1.7	lb Lime/lb SO2	50.69	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	29.80	lb/hr	
Reagent Feed rate	50.69	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	0.34	gpm	Equation 6-39 EPA/600/R-00/093
water use	0.31	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			7,967,916
Instrumentation	10%	of control device cost (A)	796,792
Sales Taxes	6.0%	of control device cost (A)	478,075
Freight	5%	of control device cost (A)	398,396
Purchased Equipment Total (B	21%		**9,641,178**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,156,941
Handling & erection	40%	of purchased equip cost (B)	3,856,471
Electrical	1%	of purchased equip cost (B)	96,412
Piping	30%	of purchased equip cost (B)	2,892,353
Insulation	1%	of purchased equip cost (B)	96,412
Painting	1%	of purchased equip cost (B)	96,412
Installation Total	85%		**8,195,001**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**17,836,180**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	964,118
Construction & field expenses	10%	of purchased equip cost (B)	964,118
Construction fee	10%	of purchased equip cost (B)	964,118
Start-up	1%	of purchased equip cost (B)	96,412
Performance test	1%	of purchased equip cost (B)	96,412
Contingencies	3%	of purchased equip cost (B)	289,235
Total Indirect Capital Costs, IC	35%		**3,374,412**
Total Capital Investment (TCI) = DC + IC			**21,210,592**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	67,625
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity	464,875
Total Annual Direct Operating Costs			**566,337**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	424,212
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	3,019,911
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**4,454,974**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**5,021,311**
Pollutant Removed (tons/yr)[B]			**117**
Cost per ton of SO2 Removed			**42,752**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1256.7	kW-hr	9,907,820	464,875	$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.3	gpm	148	30	$/Mgal, 0.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	50.69	lb/hr	222	67,625	$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.040	ton/hr	317	8,053	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
Uncontrolled Emission Rate						
0.25	lb/MMBtu	134	MMBTU/HR	NA	**130.50**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	
				90%		**Currently assumes 80%**.
				90%	**13**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**117.5**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	0	125	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	29.80	lb/hr SO2	2.50	lb NaOH/lb SO2	74.49	lb/hr Caustic
Lime Use	29.80	lb/hr SO2	1.7	lb Lime/lb SO2	50.69	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	29.80	lb/hr	
Reagent Feed rate	50.69	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	0.34	gpm	Equation 6-39 EPA/600/R-00/093
water use	0.31	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**212,376**
Instrumentation	10%	of control device cost (A)	21,238
Sales Taxes	6.0%	of control device cost (A)	12,743
Freight	5%	of control device cost (A)	10,619
Purchased Equipment Total (B	21%		**256,975**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	30,837
Handling & erection	40%	of purchased equip cost (B)	102,790
Electrical	1%	of purchased equip cost (B)	2,570
Piping	30%	of purchased equip cost (B)	77,093
Insulation	1%	of purchased equip cost (B)	2,570
Painting	1%	of purchased equip cost (B)	2,570
Installation Total	85%		**218,429**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**475,405**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	25,698
Construction & field expenses	10%	of purchased equip cost (B)	25,698
Construction fee	10%	of purchased equip cost (B)	25,698
Start-up	1%	of purchased equip cost (B)	2,570
Performance test	1%	of purchased equip cost (B)	2,570
Contingencies	3%	of purchased equip cost (B)	7,709
Total Indirect Capital Costs, IC	35%		**89,941**
Total Capital Investment (TCI) = DC + IC			**565,346**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	67,625
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity	464,875
Total Annual Direct Operating Costs			**566,337**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	11,307
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	5,653
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	5,653
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	80,493
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**689,745**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**1,256,082**
Pollutant Removed (tons/yr)[B]			**124**
Cost per ton of SO2 Removed			**10,131**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1256.7	kW-hr	9,907,820	464,875	$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.3	gpm	148	30	$/Mgal, 0.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	50.69	lb/hr	222	67,625	$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.040	ton/hr	317	8,053	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	134	MMBTU/HR	NA	**130.50**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%**.
				95%	7	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**124.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	0	125	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	29.80	lb/hr SO2	2.50	lb NaOH/lb SO2	74.49	lb/hr Caustic
Lime Use	29.80	lb/hr SO2	1.7	lb Lime/lb SO2	50.69	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	29.80	lb/hr	
Reagent Feed rate	50.69	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	0.34	gpm	Equation 6-39 EPA/600/R-00/093
water use	0.31	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**7,967,916**
Instrumentation	10%	of control device cost (A)	796,792
Sales Taxes	6.0%	of control device cost (A)	478,075
Freight	5%	of control device cost (A)	398,396
Purchased Equipment Total (B	21%		**9,641,178**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,156,941
Handling & erection	40%	of purchased equip cost (B)	3,856,471
Electrical	1%	of purchased equip cost (B)	96,412
Piping	30%	of purchased equip cost (B)	2,892,353
Insulation	1%	of purchased equip cost (B)	96,412
Painting	1%	of purchased equip cost (B)	96,412
Installation Total	85%		**8,195,001**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**17,836,180**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	964,118
Construction & field expenses	10%	of purchased equip cost (B)	964,118
Construction fee	10%	of purchased equip cost (B)	964,118
Start-up	1%	of purchased equip cost (B)	96,412
Performance test	1%	of purchased equip cost (B)	96,412
Contingencies	3%	of purchased equip cost (B)	289,235
Total Indirect Capital Costs, IC	35%		**3,374,412**
Total Capital Investment (TCI) = DC + IC			**21,210,592**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	67,625
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity	464,875
Total Annual Direct Operating Costs			**566,337**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	424,212
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	3,019,911
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**4,454,974**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**5,021,311**
Pollutant Removed (tons/yr)[B]			**124**
Cost per ton of SO2 Removed			**40,502**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cos		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1256.7	kW-hr	9,907,820	464,875	$/kW-hr, 1,257 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.3	gpm	148	30	$/Mgal, 0.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	50.69	lb/hr	222	67,625	$/Ton, 50.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.040	ton/hr	317	8,053	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculatioı

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.25	lb/MMBtu	134	MMBTU/HR	NA	**130.50**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff.** 95%	**Emis Rate T/yr**	**Currently assumes 80%**.
				95%	7	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**124.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	0	125	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	29.80	lb/hr SO2	2.50	lb NaOH/lb SO2	74.49	lb/hr Caustic
Lime Use	29.80	lb/hr SO2	1.7	lb Lime/lb SO2	50.69	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	29.80	lb/hr	
Reagent Feed rate	50.69	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	0.34	gpm	Equation 6-39 EPA/600/R-00/093
water use	0.31	gpm	

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS				
Direct Capital Costs				
Purchased Equipment (1)				
Fabric Filter (EC) + bags + auxillary equipment				**246,802**
Instrumentation	10%	of control device cost (A)		24,680
Sales Taxes	6%	of control device cost (A)		14,808
Freight	5%	of control device cost (A)		12,340
Purchased Equipment Total (B)	21%			**298,630**
Direct installation costs				
Foundations & supports	4%	of purchased equip cost (B)		11,945
Handling & erection	50%	of purchased equip cost (B)		149,315
Electrical	8%	of purchased equip cost (B)		23,890
Piping	1%	of purchased equip cost (B)		2,986
Insulation for ductwork	7%	of purchased equip cost (B)		20,904
Painting	4%	of purchased equip cost (B)		11,945
Installation Total	74%		0	**220,986**
Site Preparation, as required		Site Specific		NA
Buildings, as required		Site Specific		NA
Total Direct Capital Cost				**519,616**
Indirect Capital Costs				
Engineering	10%	of purchased equip cost (B)		29,863
Construction and field expense	20%	of purchased equip cost (B)		59,726
Contractor fees	10%	of purchased equip cost (B)		29,863
Startup	1%	of purchased equip cost (B)		2,986
Performance test	1%	of purchased equip cost (B)		2,986
Contingencies	3%	of purchased equip cost (B)		8,959
Total Indirect Capital Costs	45%			**134,384**
Total Capital Investment (TCI) = DC + IC				**654,000**
OPERATING COSTS				
Direct Operating Costs				
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity		50,025
Supervisor	15%	of operator labor costs		7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity		17,509
Maintenance Materials	100%	of maintenance labor costs		17,509
Replacement parts, bags				259,771
Utilities				
Electricity	0.05	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity		1,347,461
Compressed Air	0.27	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity		99,296
Solid Waste Disposal	25.38	$/Ton, 80.489 lb/hr, 8760 hr/yr		7,650
Total Annual Direct Operating Costs (DC				**1,806,726**
Indirect Operating Costs				
Overhead	60%	of oper, maint & supv labor + maint mtl costs		55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)		13,080
Property tax (1% total capital costs)	1%	of total capital costs (TCI)		6,540
Insurance (1% total capital costs)	1%	of total capital costs (TCI)		6,540
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate		61,733
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost		**143,421**
Total Annual Cost (Annualized Capital Cost + Operating Cost				**1,950,147**
Pollutant Removed (tons/yr				**335**
Cost per ton of PM Removed				**5,823**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	6126	Number
Total Rep Parts Cost	241,631	Cost adjusted for freight & sales tax
Installation Labor	18,140	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**259,771**	
Annualized Cost	**143,677**	

Total Cost Replacement Parts (Bags) **259,771**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	3643	kW-hr	28,718,263	1,347,461	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	765.79	Mscfm	362,248	99,296	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.038	ton/hr	301	7,650	$/Ton, 80.489 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 80.489 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	6126.290841	bags	2 yr life	143,677	$/bag, 6,126.3 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatio

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
80	lb/hr	-	MMBtu/hr	NA	**353**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**17.6**	Currently assumes 95%.
Emission Reduction T/y					**335**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	382,893	6	0.65	3642.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**3,085,022**
Instrumentation	10%	of control device cost (A)	308,502
Sales Taxes	6%	of control device cost (A)	185,101
Freight	5%	of control device cost (A)	154,251
Purchased Equipment Total (B)	21%		**3,732,877**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	149,315
Handling & erection	50%	of purchased equip cost (B)	1,866,438
Electrical	8%	of purchased equip cost (B)	298,630
Piping	1%	of purchased equip cost (B)	37,329
Insulation for ductwork	7%	of purchased equip cost (B)	261,301
Painting	4%	of purchased equip cost (B)	149,315
Installation Total	74%	0	**2,762,329**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**6,495,205**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	373,288
Construction and field expense	20%	of purchased equip cost (B)	746,575
Contractor fees	10%	of purchased equip cost (B)	373,288
Startup	1%	of purchased equip cost (B)	37,329
Performance test	1%	of purchased equip cost (B)	37,329
Contingencies	3%	of purchased equip cost (B)	111,986
Total Indirect Capital Costs	45%		**1,679,795**
Total Capital Investment (TCI) = DC + IC			**8,175,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			259,771
Utilities			
Electricity	0.05	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity	1,347,461
Compressed Air	0.27	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity	99,296
Solid Waste Disposal	25.38	$/Ton, 80.489 lb/hr, 8760 hr/yr	8,052
Total Annual Direct Operating Costs (DC			**1,807,128**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	163,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	81,750
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	81,750
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	771,662
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,154,190**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**2,961,318**
Pollutant Removed (tons/yr			**353**
Cost per ton of PM Removed			**8,401**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	\$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	\$ each
Amount Required	6126	Number
Total Rep Parts Cost	241,631	Cost adjusted for freight & sales tax
Installation Labor	18,140	10 min per bag (13 hr total) Labor at \$29.65/hr
Total Installed Cost	**259,771**	
Annualized Cost	**143,677**	

Total Cost Replacement Parts (Bags) **259,771**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost \$**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	3643	kW-hr	28,718,263	1,347,461	\$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	\$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	765.79	Mscfm	362,248	99,296	\$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	\$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	\$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.040	ton/hr	317	8,052	\$/Ton, 80.489 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	\$/Ton, 80.489 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	\$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	6126.290841	bags	2 yr life	143,677	\$/bag, 6,126.3 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatio

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
80	lb/hr	-	MMBtu/hr	NA	**353**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 95%.
Emission Reduction T/yı					**353**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	382,893	6	0.65	3642.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**531,017**
Instrumentation	10%	of control device cost (A)	53,102
Sales Taxes	6.0%	of control device cost (A)	31,861
Freight	5%	of control device cost (A)	26,551
Purchased Equipment Total (B)	21%		**642,530**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	77,104
Handling & erection	40%	of purchased equip cost (B)	257,012
Electrical	1%	of purchased equip cost (B)	6,425
Piping	30%	of purchased equip cost (B)	192,759
Insulation	1%	of purchased equip cost (B)	6,425
Painting	1%	of purchased equip cost (B)	6,425
Installation Total	85%		**546,151**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**1,188,681**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	64,253
Construction & field expenses	10%	of purchased equip cost (B)	64,253
Construction fee	10%	of purchased equip cost (B)	64,253
Start-up	1%	of purchased equip cost (B)	6,425
Performance test	1%	of purchased equip cost (B)	6,425
Contingencies	3%	of purchased equip cost (B)	19,276
Total Indirect Capital Costs, IC	35%		**224,886**
Total Capital Investment (TCI) = DC + IC			**1,413,566**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	66,775
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity	3,726,602
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity	3,930,983
Total Annual Direct Operating Costs			**7,758,197**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	28,271
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	14,136
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	14,136
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	201,260
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**8,036,301**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,794,498**
Pollutant Removed (tons/yr)[B]			**94**
Cost per ton of SO2 Removed			**168,094**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	12000	Temp Deg F	
	12%	% Moisture	
	2,874,005	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	10626.7	kW-hr	83,780,542	3,930,983	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5,173.2	gpm	2,447,135	496,880	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	59.59	lb/hr	235	66,775	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	5,173.2	gpm	2,447,135	3,726,602	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.20	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. % 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**10**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**94.0**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	2,586,605	12	0.55	0.7	9432.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	25,866	125	0.8	0.7	1085.4	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	5,173.2	62.5	0.8	0.7	108.5	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84 lb/hr SO2	2.50	lb NaOH/lb SO2	59.59 lb/hr Caustic
Lime Use	23.84 lb/hr SO2	1.53	lb Lime/lb SO2	36.47 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**7,967,916**
Instrumentation	10%	of control device cost (A)	796,792
Sales Taxes	6.0%	of control device cost (A)	478,075
Freight	5%	of control device cost (A)	398,396
Purchased Equipment Total (B)	21%		**9,641,178**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,156,941
Handling & erection	40%	of purchased equip cost (B)	3,856,471
Electrical	1%	of purchased equip cost (B)	96,412
Piping	30%	of purchased equip cost (B)	2,892,353
Insulation	1%	of purchased equip cost (B)	96,412
Painting	1%	of purchased equip cost (B)	96,412
Installation Total	85%		**8,195,001**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**17,836,180**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	964,118
Construction & field expenses	10%	of purchased equip cost (B)	964,118
Construction fee	10%	of purchased equip cost (B)	964,118
Start-up	1%	of purchased equip cost (B)	96,412
Performance test	1%	of purchased equip cost (B)	96,412
Contingencies	3%	of purchased equip cost (B)	289,235
Total Indirect Capital Costs, IC	35%		**3,374,412**
Total Capital Investment (TCI) = DC + IC			**21,210,592**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	66,775
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity	3,726,602
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity	3,930,983
Total Annual Direct Operating Costs			**7,758,197**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	424,212
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	3,019,911
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**11,646,833**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**19,405,030**
Pollutant Removed (tons/yr)[B]			**94**
Cost per ton of SO2 Removed			**206,519**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	12000	Temp Deg F	
	12%	% Moisture	
	2,874,005	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	10626.7	kW-hr	83,780,542	3,930,983	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5,173.2	gpm	2,447,135	496,880	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	59.59	lb/hr	235	66,775	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	5,173.2	gpm	2,447,135	3,726,602	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.20	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%		
				90%	**10**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**94.0**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	2,586,605	12	0.55	0.7	9432.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	25,866	125	0.8	0.7	1085.4	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	5,173.2	62.5	0.8	0.7	108.5	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84	lb/hr SO2	2.50	lb NaOH/lb SO2	59.59	lb/hr Caustic
Lime Use	23.84	lb/hr SO2	1.53	lb Lime/lb SO2	36.47	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**531,017**
Instrumentation	10%	of control device cost (A)	53,102
Sales Taxes	6.0%	of control device cost (A)	31,861
Freight	5%	of control device cost (A)	26,551
Purchased Equipment Total (B)	21%		**642,530**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	77,104
Handling & erection	40%	of purchased equip cost (B)	257,012
Electrical	1%	of purchased equip cost (B)	6,425
Piping	30%	of purchased equip cost (B)	192,759
Insulation	1%	of purchased equip cost (B)	6,425
Painting	1%	of purchased equip cost (B)	6,425
Installation Total	85%		**546,151**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**1,188,681**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	64,253
Construction & field expenses	10%	of purchased equip cost (B)	64,253
Construction fee	10%	of purchased equip cost (B)	64,253
Start-up	1%	of purchased equip cost (B)	6,425
Performance test	1%	of purchased equip cost (B)	6,425
Contingencies	3%	of purchased equip cost (B)	19,276
Total Indirect Capital Costs, IC	35%		**224,886**
Total Capital Investment (TCI) = DC + IC			**1,413,566**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	66,775
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity	3,726,602
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity	3,930,983
Total Annual Direct Operating Costs			**7,758,197**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	28,271
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	14,136
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	14,136
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	201,260
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**8,036,301**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,794,498**
Pollutant Removed (tons/yr)[B]			**104**
Cost per ton of SO2 Removed			**151,299**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	12000	Temp Deg F	
	12%	% Moisture	
	2,874,005	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	10626.7	kW-hr	83,780,542	3,930,983	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5,173.2	gpm	2,447,135	496,880	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	59.59	lb/hr	235	66,775	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	5,173.2	gpm	2,447,135	3,726,602	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.20	lb/MMBtu	134	MMBTU/HR	NA	104.40	

Controlled Emission Rate

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff.	Emis Rate T/yr	
				99.99%		Currently assumes 80%.
				99.99%	0	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					104.4	Assuming 99.99% control.

	Flow acfm	ΔP in H2O	Blower Eff	Motor Eff	kW	
Blower	2,586,605	12	0.55	0.7	9432.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	25,866	125	0.8	0.7	1085.4	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	5,173.2	62.5	0.8	0.7	108.5	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84 lb/hr SO2	2.50	lb NaOH/lb SO2	59.59 lb/hr Caustic
Lime Use	23.84 lb/hr SO2	1.53	lb Lime/lb SO2	36.47 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**7,967,916**
Instrumentation	10%	of control device cost (A)	796,792
Sales Taxes	6.0%	of control device cost (A)	478,075
Freight	5%	of control device cost (A)	398,396
Purchased Equipment Total (B)	21%		**9,641,178**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,156,941
Handling & erection	40%	of purchased equip cost (B)	3,856,471
Electrical	1%	of purchased equip cost (B)	96,412
Piping	30%	of purchased equip cost (B)	2,892,353
Insulation	1%	of purchased equip cost (B)	96,412
Painting	1%	of purchased equip cost (B)	96,412
Installation Total	85%		**8,195,001**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**17,836,180**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	964,118
Construction & field expenses	10%	of purchased equip cost (B)	964,118
Construction fee	10%	of purchased equip cost (B)	964,118
Start-up	1%	of purchased equip cost (B)	96,412
Performance test	1%	of purchased equip cost (B)	96,412
Contingencies	3%	of purchased equip cost (B)	289,235
Total Indirect Capital Costs, IC	35%		**3,374,412**
Total Capital Investment (TCI) = DC + IC			**21,210,592**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	66,775
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity	3,726,602
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity	3,930,983
Total Annual Direct Operating Costs			**7,758,197**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	424,212
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	212,106
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	3,019,911
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**11,646,833**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**19,405,030**
Pollutant Removed (tons/yr)[B]			**104**
Cost per ton of SO2 Removed			**185,886**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864	scfm
	12000	Temp Deg F		
	12%	% Moisture		
	2,874,005	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	10626.7	kW-hr	83,780,542	3,930,983	$/kW-hr, 10,627 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5,173.2	gpm	2,447,135	496,880	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	59.59	lb/hr	235	66,775	$/Ton, 59.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	5,173.2	gpm	2,447,135	3,726,602	$/Mgal, 5,173.2 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.20	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.99%		
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**104.4**	Assuming 99.99% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	2,586,605	12	0.55	0.7	9432.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	25,866	125	0.8	0.7	1085.4	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	5,173.2	62.5	0.8	0.7	108.5	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84	lb/hr SO2	2.50	lb NaOH/lb SO2	59.59	lb/hr Caustic
Lime Use	23.84	lb/hr SO2	1.53	lb Lime/lb SO2	36.47	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			1,534,003
Instrumentation	10%	of control device cost (A)	153,400
Sales Taxes	6.0%	of control device cost (A)	92,040
Freight	5%	of control device cost (A)	76,700
Purchased Equipment Total (B)	21%		1,856,144
Installation			
Foundations & supports	12%	of purchased equip cost (B)	222,737
Handling & erection	40%	of purchased equip cost (B)	742,457
Electrical	1%	of purchased equip cost (B)	18,561
Piping	30%	of purchased equip cost (B)	556,843
Insulation	1%	of purchased equip cost (B)	18,561
Painting	1%	of purchased equip cost (B)	18,561
Installation Total	85%		1,577,722
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			3,433,866
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	185,614
Construction & field expenses	10%	of purchased equip cost (B)	185,614
Construction fee	10%	of purchased equip cost (B)	185,614
Start-up	1%	of purchased equip cost (B)	18,561
Performance test	1%	of purchased equip cost (B)	18,561
Contingencies	3%	of purchased equip cost (B)	55,684
Total Indirect Capital Costs, IC	35%		649,650
Total Capital Investment (TCI) = DC + IC			4,083,516
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	49,684
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity	529,395
Total Annual Direct Operating Costs			612,916
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	81,670
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	40,835
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	40,835
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	581,401
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	1,377,959
Total Annual Cost (Annualized Capital Cost + Operating Cost)			1,990,875
Pollutant Removed (tons/yr)[B]			99
Cost per ton of SO2 Removed			20,073

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1431.1	kW-hr	11,282,931	529,395	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.4	gpm	171	35	$/Mgal, 0.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	37.24	lb/hr	163	49,684	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				95%	**5**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**99.2**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,446	125	0.8	0.7	144.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84 lb/hr SO2	2.50 lb NaOH/lb SO2	59.59	lb/hr Caustic
Limestone Use	23.84 lb/hr SO2	1.6 lb Limestone/lb SO2	37.24	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	23.84	lb/hr	
Limestone Feed rate	37.24	lb/hr	
gypsum formation rate	64	lb/hr	dry basis
gypsum formed	77	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	0	gpm	

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			**4,996,962**
Instrumentation	10%	of control device cost (A)	499,696
Sales Taxes	6.0%	of control device cost (A)	299,818
Freight	5%	of control device cost (A)	249,848
Purchased Equipment Total (B)	21%		**6,046,324**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	725,559
Handling & erection	40%	of purchased equip cost (B)	2,418,529
Electrical	1%	of purchased equip cost (B)	60,463
Piping	30%	of purchased equip cost (B)	1,813,897
Insulation	1%	of purchased equip cost (B)	60,463
Painting	1%	of purchased equip cost (B)	60,463
Installation Total	85%		**5,139,375**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**11,185,699**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	604,632
Construction & field expenses	10%	of purchased equip cost (B)	604,632
Construction fee	10%	of purchased equip cost (B)	604,632
Start-up	1%	of purchased equip cost (B)	60,463
Performance test	1%	of purchased equip cost (B)	60,463
Contingencies	3%	of purchased equip cost (B)	181,390
Total Indirect Capital Costs, IC	35%		**2,116,213**
Total Capital Investment (TCI) = DC + IC			**13,301,912**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	49,684
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity	529,395
Total Annual Direct Operating Costs			**612,916**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	266,038
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	133,019
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	133,019
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	1,893,893
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**3,059,187**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,672,103**
Pollutant Removed (tons/yr)[B]			**99**
Cost per ton of SO2 Removed			**37,024**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1431.1	kW-hr	11,282,931	529,395	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.4	gpm	171	35	$/Mgal, 0.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	37.24	lb/hr	163	49,684	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				95%	**5**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**99.2**	Assuming 95% control.

	Flow acfm	ΔP in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,446	125	0.8	0.7	144.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84	lb/hr SO2	2.50	lb NaOH/lb SO2	59.59	lb/hr Caustic
Limestone Use	23.84	lb/hr SO2	1.6	lb Limestone/lb SO2	37.24	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	23.84	lb/hr		
Limestone Feed rate	37.24	lb/hr		
gypsum formation rate	64	lb/hr	dry basis	
gypsum formed	77	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	0	gpm		

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			1,534,003
Instrumentation	10%	of control device cost (A)	153,400
Sales Taxes	6.0%	of control device cost (A)	92,040
Freight	5%	of control device cost (A)	76,700
Purchased Equipment Total (B)	21%		1,856,144
Installation			
Foundations & supports	12%	of purchased equip cost (B)	222,737
Handling & erection	40%	of purchased equip cost (B)	742,457
Electrical	1%	of purchased equip cost (B)	18,561
Piping	30%	of purchased equip cost (B)	556,843
Insulation	1%	of purchased equip cost (B)	18,561
Painting	1%	of purchased equip cost (B)	18,561
Installation Total	85%		1,577,722
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			3,433,866
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	185,614
Construction & field expenses	10%	of purchased equip cost (B)	185,614
Construction fee	10%	of purchased equip cost (B)	185,614
Start-up	1%	of purchased equip cost (B)	18,561
Performance test	1%	of purchased equip cost (B)	18,561
Contingencies	3%	of purchased equip cost (B)	55,684
Total Indirect Capital Costs, IC	35%		649,650
Total Capital Investment (TCI) = DC + IC			4,083,516
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	49,684
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity	529,395
Total Annual Direct Operating Costs			612,916
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	81,670
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	40,835
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	40,835
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	581,401
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	1,377,959
Total Annual Cost (Annualized Capital Cost + Operating Cost)			1,990,875
Pollutant Removed (tons/yr)[B]			104
Cost per ton of SO2 Removed			19,165

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1431.1	kW-hr	11,282,931	529,395	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.4	gpm	171	35	$/Mgal, 0.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	37.24	lb/hr	163	49,684	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.50%	**1**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**103.9**	Assuming 99.5% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,446	125	0.8	0.7	144.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84 lb/hr SO2	2.50 lb NaOH/lb SO2	59.59	lb/hr Caustic
Limestone Use	23.84 lb/hr SO2	1.6 lb Limestone/lb SO2	37.24	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	23.84	lb/hr		
Limestone Feed rate	37.24	lb/hr		
gypsum formation rate	64	lb/hr	dry basis	
gypsum formed	77	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	0	gpm		

Centrifuge
horse power 40 30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			**4,996,962**
Instrumentation	10%	of control device cost (A)	499,696
Sales Taxes	6.0%	of control device cost (A)	299,818
Freight	5%	of control device cost (A)	249,848
Purchased Equipment Total (B)	21%		**6,046,324**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	725,559
Handling & erection	40%	of purchased equip cost (B)	2,418,529
Electrical	1%	of purchased equip cost (B)	60,463
Piping	30%	of purchased equip cost (B)	1,813,897
Insulation	1%	of purchased equip cost (B)	60,463
Painting	1%	of purchased equip cost (B)	60,463
Installation Total	85%		**5,139,375**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**11,185,699**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	604,632
Construction & field expenses	10%	of purchased equip cost (B)	604,632
Construction fee	10%	of purchased equip cost (B)	604,632
Start-up	1%	of purchased equip cost (B)	60,463
Performance test	1%	of purchased equip cost (B)	60,463
Contingencies	3%	of purchased equip cost (B)	181,390
Total Indirect Capital Costs, IC	35%		**2,116,213**
Total Capital Investment (TCI) = DC + IC			**13,301,912**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	49,684
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity	529,395
Total Annual Direct Operating Costs			**612,916**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	266,038
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	133,019
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	133,019
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	1,893,893
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**3,059,187**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,672,103**
Pollutant Removed (tons/yr)[B]			**104**
Cost per ton of SO2 Removed			**35,349**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations **Annual hours of operation:** **8,760**
Utilization Rate: **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	1431.1	kW-hr	11,282,931	529,395	$/kW-hr, 1,431 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	0.4	gpm	171	35	$/Mgal, 0.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	37.24	lb/hr	163	49,684	$/Ton, 37.2 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.2	lb/MMBtu	134	MMBTU/HR	NA	**104.40**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**T/yr**	**Currently assumes 80%.**
				99.50%	1	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**103.9**	Assuming 99.5% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	344,604	12	0.55	0.7	1256.7	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	3,446	125	0.8	0.7	144.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	23.84	lb/hr SO2	2.50	lb NaOH/lb SO2	59.59	lb/hr Caustic
Limestone Use	23.84	lb/hr SO2	1.6	lb Limestone/lb SO2	37.24	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	23.84	lb/hr		
Limestone Feed rate	37.24	lb/hr		
gypsum formation rate	64	lb/hr	dry basis	
gypsum formed	77	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	0	gpm		

Centrifuge horse power	40	30 kW

SO_x Coke Underfire

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			**7,441,059**
Instrumentation	10%	of control device cost (A)	744,106
Sales Taxes	6.0%	of control device cost (A)	446,464
Freight	5%	of control device cost (A)	372,053
Purchased Equipment Total (B)	21%		**9,003,682**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,080,442
Handling & erection	40%	of purchased equip cost (B)	3,601,473
Electrical	1%	of purchased equip cost (B)	90,037
Piping	30%	of purchased equip cost (B)	2,701,105
Insulation	1%	of purchased equip cost (B)	90,037
Painting	1%	of purchased equip cost (B)	90,037
Installation Total	85%		**7,653,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**16,656,811**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	900,368
Construction & field expenses	10%	of purchased equip cost (B)	900,368
Construction fee	10%	of purchased equip cost (B)	900,368
Start-up	1%	of purchased equip cost (B)	90,037
Performance test	1%	of purchased equip cost (B)	90,037
Contingencies	3%	of purchased equip cost (B)	270,110
Total Indirect Capital Costs, IC	35%		**3,151,289**
Total Capital Investment (TCI) = DC + IC			**19,808,100**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,162
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	2,820,228
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**5,477,013**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,321,173**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**4,734**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65	lb/hr SO2	1.6	lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr		
Limestone Feed rate	580.70	lb/hr		
gypsum formation rate	999	lb/hr	dry basis	
gypsum formed	1199	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm		

Centrifuge
horse power 40 30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**24,238,993**
Instrumentation	10%	of control device cost (A)	2,423,899
Sales Taxes	6.0%	of control device cost (A)	1,454,340
Freight	5%	of control device cost (A)	1,211,950
Purchased Equipment Total (B)	21%		**29,329,182**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,519,502
Handling & erection	40%	of purchased equip cost (B)	11,731,673
Electrical	1%	of purchased equip cost (B)	293,292
Piping	30%	of purchased equip cost (B)	8,798,755
Insulation	1%	of purchased equip cost (B)	293,292
Painting	1%	of purchased equip cost (B)	293,292
Installation Total	85%		**24,929,805**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**54,258,986**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,932,918
Construction & field expenses	10%	of purchased equip cost (B)	2,932,918
Construction fee	10%	of purchased equip cost (B)	2,932,918
Start-up	1%	of purchased equip cost (B)	293,292
Performance test	1%	of purchased equip cost (B)	293,292
Contingencies	3%	of purchased equip cost (B)	879,875
Total Indirect Capital Costs, IC	35%		**10,265,214**
Total Capital Investment (TCI) = DC + IC			**64,524,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,290,484
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	9,186,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**13,632,224**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,476,383**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**10,008**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65 lb/hr SO2	2.50 lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65 lb/hr SO2	1.6 lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65 lb/hr		
Limestone Feed rate	580.70 lb/hr		
gypsum formation rate	999 lb/hr	dry basis	
gypsum formed	1199 lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6 gpm		

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			**7,441,059**
Instrumentation	10%	of control device cost (A)	744,106
Sales Taxes	6.0%	of control device cost (A)	446,464
Freight	5%	of control device cost (A)	372,053
Purchased Equipment Total (B)	21%		**9,003,682**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,080,442
Handling & erection	40%	of purchased equip cost (B)	3,601,473
Electrical	1%	of purchased equip cost (B)	90,037
Piping	30%	of purchased equip cost (B)	2,701,105
Insulation	1%	of purchased equip cost (B)	90,037
Painting	1%	of purchased equip cost (B)	90,037
Installation Total	85%		**7,653,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**16,656,811**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	900,368
Construction & field expenses	10%	of purchased equip cost (B)	900,368
Construction fee	10%	of purchased equip cost (B)	900,368
Start-up	1%	of purchased equip cost (B)	90,037
Performance test	1%	of purchased equip cost (B)	90,037
Contingencies	3%	of purchased equip cost (B)	270,110
Total Indirect Capital Costs, IC	35%		**3,151,289**
Total Capital Investment (TCI) = DC + IC			**19,808,100**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,162
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	2,820,228
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**5,477,013**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,321,173**
Pollutant Removed (tons/yr)[B]			**1,620**
Cost per ton of SO2 Removed			**4,520**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.50%	**8**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1619.7**	Assuming 99.5% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65 lb/hr SO2	2.50 lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65 lb/hr SO2	1.6 lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Limestone Feed rate	580.70	lb/hr	
gypsum formation rate	999	lb/hr	dry basis
gypsum formed	1199	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm	

Centrifuge
horse power 40 30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			**24,238,993**
Instrumentation	10%	of control device cost (A)	2,423,899
Sales Taxes	6.0%	of control device cost (A)	1,454,340
Freight	5%	of control device cost (A)	1,211,950
Purchased Equipment Total (B)	21%		**29,329,182**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,519,502
Handling & erection	40%	of purchased equip cost (B)	11,731,673
Electrical	1%	of purchased equip cost (B)	293,292
Piping	30%	of purchased equip cost (B)	8,798,755
Insulation	1%	of purchased equip cost (B)	293,292
Painting	1%	of purchased equip cost (B)	293,292
Installation Total	85%		**24,929,805**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**54,258,986**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,932,918
Construction & field expenses	10%	of purchased equip cost (B)	2,932,918
Construction fee	10%	of purchased equip cost (B)	2,932,918
Start-up	1%	of purchased equip cost (B)	293,292
Performance test	1%	of purchased equip cost (B)	293,292
Contingencies	3%	of purchased equip cost (B)	879,875
Total Indirect Capital Costs, IC	35%		**10,265,214**
Total Capital Investment (TCI) = DC + IC			**64,524,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,290,484
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	9,186,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**13,632,224**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,476,383**
Pollutant Removed (tons/yr)[B]			**1,620**
Cost per ton of SO2 Removed			**9,555**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.50%	**8**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1619.7**	Assuming 99.5% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65	lb/hr SO2	1.6	lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Limestone Feed rate	580.70	lb/hr	
gypsum formation rate	999	lb/hr	dry basis
gypsum formed	1199	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm	

Centrifuge
horse power 40 30 kW

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			1,030,184
Instrumentation	10%	of control device cost (A)	103,018
Sales Taxes	6.0%	of control device cost (A)	61,811
Freight	5%	of control device cost (A)	51,509
Purchased Equipment Total (B	21%		**1,246,523**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	149,583
Handling & erection	40%	of purchased equip cost (B)	498,609
Electrical	1%	of purchased equip cost (B)	12,465
Piping	30%	of purchased equip cost (B)	373,957
Insulation	1%	of purchased equip cost (B)	12,465
Painting	1%	of purchased equip cost (B)	12,465
Installation Total	85%		**1,059,544**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**2,306,067**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	124,652
Construction & field expenses	10%	of purchased equip cost (B)	124,652
Construction fee	10%	of purchased equip cost (B)	124,652
Start-up	1%	of purchased equip cost (B)	12,465
Performance test	1%	of purchased equip cost (B)	12,465
Contingencies	3%	of purchased equip cost (B)	37,396
Total Indirect Capital Costs, IC	35%		**436,283**
Total Capital Investment (TCI) = DC + IC			**2,742,350**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	54,847
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	390,449
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**2,316,760**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,113,075**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**2,807**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cos		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculatio

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%**.
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**20,580,927**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**22,377,242**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**15,274**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**1,030,184**
Instrumentation	10%	of control device cost (A)	103,018
Sales Taxes	6.0%	of control device cost (A)	61,811
Freight	5%	of control device cost (A)	51,509
Purchased Equipment Total (B	21%		**1,246,523**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	149,583
Handling & erection	40%	of purchased equip cost (B)	498,609
Electrical	1%	of purchased equip cost (B)	12,465
Piping	30%	of purchased equip cost (B)	373,957
Insulation	1%	of purchased equip cost (B)	12,465
Painting	1%	of purchased equip cost (B)	12,465
Installation Total	85%		**1,059,544**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**2,306,067**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	124,652
Construction & field expenses	10%	of purchased equip cost (B)	124,652
Construction fee	10%	of purchased equip cost (B)	124,652
Start-up	1%	of purchased equip cost (B)	12,465
Performance test	1%	of purchased equip cost (B)	12,465
Contingencies	3%	of purchased equip cost (B)	37,396
Total Indirect Capital Costs, IC	35%		**436,283**
Total Capital Investment (TCI) = DC + IC			**2,742,350**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	54,847
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	390,449
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**2,316,760**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**4,113,075**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**2,660**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%**.
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**20,580,927**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**22,377,242**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**14,470**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 95%**	**Emis Rate T/yr**	**Currently assumes 80%**.
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**1,410,846**
Instrumentation	10%	of control device cost (A)	141,085
Sales Taxes	6%	of control device cost (A)	84,651
Freight	5%	of control device cost (A)	70,542
Purchased Equipment Total (B)	21%		**1,707,123**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	68,285
Handling & erection	50%	of purchased equip cost (B)	853,562
Electrical	8%	of purchased equip cost (B)	136,570
Piping	1%	of purchased equip cost (B)	17,071
Insulation for ductwork	7%	of purchased equip cost (B)	119,499
Painting	4%	of purchased equip cost (B)	68,285
Installation Total	74%	0	**1,263,271**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**2,970,395**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	170,712
Construction and field expense	20%	of purchased equip cost (B)	341,425
Contractor fees	10%	of purchased equip cost (B)	170,712
Startup	1%	of purchased equip cost (B)	17,071
Performance test	1%	of purchased equip cost (B)	17,071
Contingencies	3%	of purchased equip cost (B)	51,214
Total Indirect Capital Costs	45%		**768,205**
Total Capital Investment (TCI) = DC + IC			**3,738,600**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			513,483
Utilities			
Electricity	0.05	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity	2,663,491
Compressed Air	0.27	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity	196,276
Solid Waste Disposal	25.38	$/Ton, 1,003.963 lb/hr, 8760 hr/yr	95,425
Total Annual Direct Operating Costs (DC			**3,561,223**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	74,772
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	37,386
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	37,386
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	352,897
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**557,970**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**4,119,192**
Pollutant Removed (tons/yr			**4,177**
Cost per ton of PM Removed			**986**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	12110	Number
Total Rep Parts Cost	477,625	Cost adjusted for freight & sales tax
Installation Labor	35,858	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**513,483**	
Annualized Cost	**284,003**	

Total Cost Replacement Parts (Bags) **513,483**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	7200	kW-hr	56,766,646	2,663,491	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1513.71	Mscfm	716,045	196,276	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.477	ton/hr	3,760	95,425	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	12109.68004	bags	2 yr life	284,003	$/bag, 12,109.7 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatio

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
1004	lb/hr	-	MMBtu/hr	NA	**4397**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**219.9**	Currently assumes 95%.
Emission Reduction T/yı					**4,177**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	756,855	6	0.65	7200.2	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**17,635,571**
Instrumentation	10%	of control device cost (A)	1,763,557
Sales Taxes	6%	of control device cost (A)	1,058,134
Freight	5%	of control device cost (A)	881,779
Purchased Equipment Total (B)	21%		**21,339,041**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	853,562
Handling & erection	50%	of purchased equip cost (B)	10,669,521
Electrical	8%	of purchased equip cost (B)	1,707,123
Piping	1%	of purchased equip cost (B)	213,390
Insulation for ductwork	7%	of purchased equip cost (B)	1,493,733
Painting	4%	of purchased equip cost (B)	853,562
Installation Total	74%	0	**15,790,890**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**37,129,932**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	2,133,904
Construction and field expense	20%	of purchased equip cost (B)	4,267,808
Contractor fees	10%	of purchased equip cost (B)	2,133,904
Startup	1%	of purchased equip cost (B)	213,390
Performance test	1%	of purchased equip cost (B)	213,390
Contingencies	3%	of purchased equip cost (B)	640,171
Total Indirect Capital Costs	45%		**9,602,568**
Total Capital Investment (TCI) = DC + IC			**46,732,500**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			513,483
Utilities			
Electricity	0.05	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity	2,663,491
Compressed Air	0.27	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity	196,276
Solid Waste Disposal	25.38	$/Ton, 1,003.963 lb/hr, 8760 hr/yr	100,437
Total Annual Direct Operating Costs (DC			**3,566,235**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	934,650
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	467,325
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	467,325
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	4,411,217
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,336,046**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**9,902,280**
Pollutant Removed (tons/yr			**4,397**
Cost per ton of PM Removed			**2,252**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	12110	Number
Total Rep Parts Cost	477,625	Cost adjusted for freight & sales tax
Installation Labor	35,858	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**513,483**	
Annualized Cost	**284,003**	

Total Cost Replacement Parts (Bags) **513,483**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations **Annual hours of operation: 8,760**
Utilization Rate: 90.0%

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	7200	kW-hr	56,766,646	2,663,491	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1513.71	Mscfm	716,045	196,276	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.502	ton/hr	3,957	100,437	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	12109.68004	bags	2 yr life	284,003	$/bag, 12,109.7 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatioı

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
1004	lb/hr	-	MMBtu/hr	NA	**4397**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.4**	Currently assumes 95%.
Emission Reduction T/yı					**4,397**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	756,855	6	0.65	7200.2	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**2,575,826**
Instrumentation	10%	of control device cost (A)	257,583
Sales Taxes	6.0%	of control device cost (A)	154,550
Freight	5%	of control device cost (A)	128,791
Purchased Equipment Total (B)	21%		**3,116,750**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	374,010
Handling & erection	40%	of purchased equip cost (B)	1,246,700
Electrical	1%	of purchased equip cost (B)	31,168
Piping	30%	of purchased equip cost (B)	935,025
Insulation	1%	of purchased equip cost (B)	31,168
Painting	1%	of purchased equip cost (B)	31,168
Installation Total	85%		**2,649,238**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**5,765,988**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	311,675
Construction & field expenses	10%	of purchased equip cost (B)	311,675
Construction fee	10%	of purchased equip cost (B)	311,675
Start-up	1%	of purchased equip cost (B)	31,168
Performance test	1%	of purchased equip cost (B)	31,168
Contingencies	3%	of purchased equip cost (B)	93,503
Total Indirect Capital Costs, IC	35%		**1,090,863**
Total Capital Investment (TCI) = DC + IC			**6,856,850**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	137,137
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	976,261
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,362,401**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,453,964**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**5,088**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.53	lb Lime/lb SO2	568.62	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B)	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**21,876,176**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**24,967,739**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**17,042**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65 lb/hr SO2	2.50	lb NaOH/lb SO2	929.12 lb/hr Caustic
Lime Use	371.65 lb/hr SO2	1.53	lb Lime/lb SO2	568.62 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**2,575,826**
Instrumentation	10%	of control device cost (A)	257,583
Sales Taxes	6.0%	of control device cost (A)	154,550
Freight	5%	of control device cost (A)	128,791
Purchased Equipment Total (B)	21%		**3,116,750**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	374,010
Handling & erection	40%	of purchased equip cost (B)	1,246,700
Electrical	1%	of purchased equip cost (B)	31,168
Piping	30%	of purchased equip cost (B)	935,025
Insulation	1%	of purchased equip cost (B)	31,168
Painting	1%	of purchased equip cost (B)	31,168
Installation Total	85%		**2,649,238**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**5,765,988**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	311,675
Construction & field expenses	10%	of purchased equip cost (B)	311,675
Construction fee	10%	of purchased equip cost (B)	311,675
Start-up	1%	of purchased equip cost (B)	31,168
Performance test	1%	of purchased equip cost (B)	31,168
Contingencies	3%	of purchased equip cost (B)	93,503
Total Indirect Capital Costs, IC	35%		**1,090,863**
Total Capital Investment (TCI) = DC + IC			**6,856,850**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	137,137
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	976,261
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,362,401**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,453,964**
Pollutant Removed (tons/yr)[B]			**1,628**
Cost per ton of SO2 Removed			**4,580**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	
				99.99%		**Currently assumes 80%.**
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1627.7**	Assuming 99.99% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.53	lb Lime/lb SO2	568.62	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B)	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**21,876,176**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**24,967,739**
Pollutant Removed (tons/yr)[B]			**1,628**
Cost per ton of SO2 Removed			**15,340**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.99%		
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1627.7**	Assuming 99.99% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65 lb/hr SO2	2.50	lb NaOH/lb SO2	929.12 lb/hr Caustic
Lime Use	371.65 lb/hr SO2	1.53	lb Lime/lb SO2	568.62 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO_x Sinter Windbox

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			7,441,059
Instrumentation	10%	of control device cost (A)	744,106
Sales Taxes	6.0%	of control device cost (A)	446,464
Freight	5%	of control device cost (A)	372,053
Purchased Equipment Total (B)	21%		**9,003,682**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,080,442
Handling & erection	40%	of purchased equip cost (B)	3,601,473
Electrical	1%	of purchased equip cost (B)	90,037
Piping	30%	of purchased equip cost (B)	2,701,105
Insulation	1%	of purchased equip cost (B)	90,037
Painting	1%	of purchased equip cost (B)	90,037
Installation Total	85%		**7,653,130**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**16,656,811**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	900,368
Construction & field expenses	10%	of purchased equip cost (B)	900,368
Construction fee	10%	of purchased equip cost (B)	900,368
Start-up	1%	of purchased equip cost (B)	90,037
Performance test	1%	of purchased equip cost (B)	90,037
Contingencies	3%	of purchased equip cost (B)	270,110
Total Indirect Capital Costs, IC	35%		**3,151,289**
Total Capital Investment (TCI) = DC + IC			**19,808,100**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,162
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	2,820,228
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**5,477,013**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,321,173**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**4,734**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.6	lb/MMBtu	650	MMBTU/HR	NA	1,627.81	
Controlled Emission Rate						
Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. 95%	Emis Rate T/yr	Currently assumes 80%.
				95%	81	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					1546.4	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65	lb/hr SO2	1.6	lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rat
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr		
Limestone Feed rate	580.70	lb/hr		
gypsum formation rate	999	lb/hr	dry basis	
gypsum formed	1199	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm		

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**24,238,993**
Instrumentation	10%	of control device cost (A)	2,423,899
Sales Taxes	6.0%	of control device cost (A)	1,454,340
Freight	5%	of control device cost (A)	1,211,950
Purchased Equipment Total (B)	21%		**29,329,182**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,519,502
Handling & erection	40%	of purchased equip cost (B)	11,731,673
Electrical	1%	of purchased equip cost (B)	293,292
Piping	30%	of purchased equip cost (B)	8,798,755
Insulation	1%	of purchased equip cost (B)	293,292
Painting	1%	of purchased equip cost (B)	293,292
Installation Total	85%		**24,929,805**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**54,258,986**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,932,918
Construction & field expenses	10%	of purchased equip cost (B)	2,932,918
Construction fee	10%	of purchased equip cost (B)	2,932,918
Start-up	1%	of purchased equip cost (B)	293,292
Performance test	1%	of purchased equip cost (B)	293,292
Contingencies	3%	of purchased equip cost (B)	879,875
Total Indirect Capital Costs, IC	35%		**10,265,214**
Total Capital Investment (TCI) = DC + IC			**64,524,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,290,484
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	9,186,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**13,632,224**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,476,383**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**10,008**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%		**Currently assumes 80%.**
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 95% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65	lb/hr SO2	1.6	lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Limestone Feed rate	580.70	lb/hr	
gypsum formation rate	999	lb/hr	dry basis
gypsum formed	1199	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm	

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			7,441,059
Instrumentation	10%	of control device cost (A)	744,106
Sales Taxes	6.0%	of control device cost (A)	446,464
Freight	5%	of control device cost (A)	372,053
Purchased Equipment Total (B)	21%		9,003,682
Installation			
Foundations & supports	12%	of purchased equip cost (B)	1,080,442
Handling & erection	40%	of purchased equip cost (B)	3,601,473
Electrical	1%	of purchased equip cost (B)	90,037
Piping	30%	of purchased equip cost (B)	2,701,105
Insulation	1%	of purchased equip cost (B)	90,037
Painting	1%	of purchased equip cost (B)	90,037
Installation Total	85%		7,653,130
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			16,656,811
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	900,368
Construction & field expenses	10%	of purchased equip cost (B)	900,368
Construction fee	10%	of purchased equip cost (B)	900,368
Start-up	1%	of purchased equip cost (B)	90,037
Performance test	1%	of purchased equip cost (B)	90,037
Contingencies	3%	of purchased equip cost (B)	270,110
Total Indirect Capital Costs, IC	35%		3,151,289
Total Capital Investment (TCI) = DC + IC			19,808,100
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	\$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	\$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	\$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	\$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	\$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			1,844,159
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,162
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,081
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	2,820,228
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	5,477,013
Total Annual Cost (Annualized Capital Cost + Operating Cost)			7,321,173
Pollutant Removed (tons/yr)[B]			1,620
Cost per ton of SO2 Removed			4,520

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.50%	**8**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1619.7**	Assuming 99.5% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65	lb/hr SO2	1.6	lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Limestone Feed rate	580.70	lb/hr	
gypsum formation rate	999	lb/hr	dry basis
gypsum formed	1199	lb/hr	wet basis (20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm	

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, E(			**24,238,993**
Instrumentation	10%	of control device cost (A)	2,423,899
Sales Taxes	6.0%	of control device cost (A)	1,454,340
Freight	5%	of control device cost (A)	1,211,950
Purchased Equipment Total (B)	21%		**29,329,182**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	3,519,502
Handling & erection	40%	of purchased equip cost (B)	11,731,673
Electrical	1%	of purchased equip cost (B)	293,292
Piping	30%	of purchased equip cost (B)	8,798,755
Insulation	1%	of purchased equip cost (B)	293,292
Painting	1%	of purchased equip cost (B)	293,292
Installation Total	85%		**24,929,805**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**54,258,986**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	2,932,918
Construction & field expenses	10%	of purchased equip cost (B)	2,932,918
Construction fee	10%	of purchased equip cost (B)	2,932,918
Start-up	1%	of purchased equip cost (B)	293,292
Performance test	1%	of purchased equip cost (B)	293,292
Contingencies	3%	of purchased equip cost (B)	879,875
Total Indirect Capital Costs, IC	35%		**10,265,214**
Total Capital Investment (TCI) = DC + IC			**64,524,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	774,658
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,665
Total Annual Direct Operating Costs			**1,844,159**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,290,484
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	645,242
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	9,186,794
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cos	**13,632,224**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**15,476,383**
Pollutant Removed (tons/yr)[B]			**1,620**
Cost per ton of SO2 Removed			**9,555**

BART ANALYSIS 2004
ADVANCED FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2799.7	kW-hr	22,072,999	1,035,665	$/kW-hr, 2,800 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	5.6	gpm	2,663	541	$/Mgal, 5.6 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1	Mscfm	473	130	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Limestone)	304.57	Ton	580.70	lb/hr	2,543	774,658	$/Ton, 580.7 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.6	lb/MMBtu	650	MMBTU/HR	NA	1,627.81	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 99.50%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				99.50%	8	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					1619.7	Assuming 99.5% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Limestone Use	371.65	lb/hr SO2	1.6	lb Limestone/lb SO2	580.70	lb/hr Limestone

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr		
Limestone Feed rate	580.70	lb/hr		
gypsum formation rate	999	lb/hr	dry basis	
gypsum formed	1199	lb/hr	wet basis	(20 % of gypsum out of centrifuge is assumed to be water
Water required for gypsum formation	6	gpm		

Centrifuge horse power	40	30 kW

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			1,030,184
Instrumentation	10%	of control device cost (A)	103,018
Sales Taxes	6.0%	of control device cost (A)	61,811
Freight	5%	of control device cost (A)	51,509
Purchased Equipment Total (B	21%		1,246,523
Installation			
Foundations & supports	12%	of purchased equip cost (B)	149,583
Handling & erection	40%	of purchased equip cost (B)	498,609
Electrical	1%	of purchased equip cost (B)	12,465
Piping	30%	of purchased equip cost (B)	373,957
Insulation	1%	of purchased equip cost (B)	12,465
Painting	1%	of purchased equip cost (B)	12,465
Installation Total	85%		1,059,544
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			2,306,067
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	124,652
Construction & field expenses	10%	of purchased equip cost (B)	124,652
Construction fee	10%	of purchased equip cost (B)	124,652
Start-up	1%	of purchased equip cost (B)	12,465
Performance test	1%	of purchased equip cost (B)	12,465
Contingencies	3%	of purchased equip cost (B)	37,396
Total Indirect Capital Costs, IC	35%		436,283
Total Capital Investment (TCI) = DC + IC			2,742,350
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			1,796,315
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	54,847
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	390,449
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	2,316,760
Total Annual Cost (Annualized Capital Cost + Operating Cost)			4,113,075
Pollutant Removed (tons/yr)[B]			1,465
Cost per ton of SO2 Removed			2,807

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	ΔP in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**20,580,927**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**22,377,242**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**15,274**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%		**Currently assumes 80%**.
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**1,030,184**
Instrumentation	10%	of control device cost (A)	103,018
Sales Taxes	6.0%	of control device cost (A)	61,811
Freight	5%	of control device cost (A)	51,509
Purchased Equipment Total (B	21%		**1,246,523**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	149,583
Handling & erection	40%	of purchased equip cost (B)	498,609
Electrical	1%	of purchased equip cost (B)	12,465
Piping	30%	of purchased equip cost (B)	373,957
Insulation	1%	of purchased equip cost (B)	12,465
Painting	1%	of purchased equip cost (B)	12,465
Installation Total	85%		**1,059,544**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**2,306,067**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	124,652
Construction & field expenses	10%	of purchased equip cost (B)	124,652
Construction fee	10%	of purchased equip cost (B)	124,652
Start-up	1%	of purchased equip cost (B)	12,465
Performance test	1%	of purchased equip cost (B)	12,465
Contingencies	3%	of purchased equip cost (B)	37,396
Total Indirect Capital Costs, IC	35%		**436,283**
Total Capital Investment (TCI) = DC + IC			**2,742,350**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	54,847
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	27,424
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	390,449
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**2,316,760**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**4,113,075**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**2,660**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cos		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations **Annual hours of operation:** **8,760**
Utilization Rate: **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculatioı

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95%		**Currently assumes 80%**.
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Reagent #2	304.57	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	843,516
Catalyst	NA		-
Wastewater Treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	-
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity	918,962
Total Annual Direct Operating Costs			**1,796,315**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Cost		Sum indirect oper costs + capital recovery cost	**20,580,927**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**22,377,242**
Pollutant Removed (tons/yr)[B]			**1,546**
Cost per ton of SO2 Removed			**14,470**

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BART ANALYSIS 2004
DRY FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations			**Annual hours of operation:**		**8,760**		
			Utilization Rate:		**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2484.2	kW-hr	19,585,723	918,962	$/kW-hr, 2,484 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	3.9	gpm	1,843	374	$/Mgal, 3.9 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	1	Mscfm	473	118	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280.00	Ton	0.00	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	304.57	Ton	632.32	lb/hr	2,770	843,516	$/Ton, 632.3 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25.38	Ton	0.502	ton/hr	3,958	100,447	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				95%		
				95%	**81**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1546.4**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	4	125	0.8	0.7	0.2	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	0.0	62.5	0.8	0.7	0.0	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.7	lb Lime/lb SO2	632.32	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

SO2 flow rate	371.65	lb/hr	
Reagent Feed rate	632.32	lb/hr	Equation 6-38 EPA/600/R-00/093
Reagent flow rate	4.28	gpm	Equation 6-39 EPA/600/R-00/093
water use	3.90	gpm	

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**1,410,846**
Instrumentation	10%	of control device cost (A)	141,085
Sales Taxes	6%	of control device cost (A)	84,651
Freight	5%	of control device cost (A)	70,542
Purchased Equipment Total (B)	21%		**1,707,123**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	68,285
Handling & erection	50%	of purchased equip cost (B)	853,562
Electrical	8%	of purchased equip cost (B)	136,570
Piping	1%	of purchased equip cost (B)	17,071
Insulation for ductwork	7%	of purchased equip cost (B)	119,499
Painting	4%	of purchased equip cost (B)	68,285
Installation Total	74%	0	**1,263,271**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**2,970,395**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	170,712
Construction and field expense	20%	of purchased equip cost (B)	341,425
Contractor fees	10%	of purchased equip cost (B)	170,712
Startup	1%	of purchased equip cost (B)	17,071
Performance test	1%	of purchased equip cost (B)	17,071
Contingencies	3%	of purchased equip cost (B)	51,214
Total Indirect Capital Costs	45%		**768,205**
Total Capital Investment (TCI) = DC + IC			**3,738,600**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			513,483
Utilities			
Electricity	0.05	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity	2,663,491
Compressed Air	0.27	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity	196,276
Solid Waste Disposal	25.38	$/Ton, 1,003.963 lb/hr, 8760 hr/yr	95,425
Total Annual Direct Operating Costs (DC			**3,561,223**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	74,772
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	37,386
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	37,386
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	352,897
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**557,970**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**4,119,192**
Pollutant Removed (tons/yr			**4,177**
Cost per ton of PM Removed			**986**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	12110	Number
Total Rep Parts Cost	477,625	Cost adjusted for freight & sales tax
Installation Labor	35,858	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**513,483**	
Annualized Cost	**284,003**	

Total Cost Replacement Parts (Bags) **513,483**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	7200	kW-hr	56,766,646	2,663,491	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1513.71	Mscfm	716,045	196,276	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.477	ton/hr	3,760	95,425	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	12109.68004	bags	2 yr life	284,003	$/bag, 12,109.7 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatioı

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
1004	lb/hr	-	MMBtu/hr	NA	**4397**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**219.9**	Currently assumes 95%.
Emission Reduction T/yı					**4,177**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	756,855	6	0.65	7200.2	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**17,635,571**
Instrumentation	10%	of control device cost (A)	1,763,557
Sales Taxes	6%	of control device cost (A)	1,058,134
Freight	5%	of control device cost (A)	881,779
Purchased Equipment Total (B)	21%		**21,339,041**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	853,562
Handling & erection	50%	of purchased equip cost (B)	10,669,521
Electrical	8%	of purchased equip cost (B)	1,707,123
Piping	1%	of purchased equip cost (B)	213,390
Insulation for ductwork	7%	of purchased equip cost (B)	1,493,733
Painting	4%	of purchased equip cost (B)	853,562
Installation Total	74%	0	**15,790,890**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**37,129,932**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	2,133,904
Construction and field expense	20%	of purchased equip cost (B)	4,267,808
Contractor fees	10%	of purchased equip cost (B)	2,133,904
Startup	1%	of purchased equip cost (B)	213,390
Performance test	1%	of purchased equip cost (B)	213,390
Contingencies	3%	of purchased equip cost (B)	640,171
Total Indirect Capital Costs	45%		**9,602,568**
Total Capital Investment (TCI) = DC + IC			**46,732,500**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			513,483
Utilities			
Electricity	0.05	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity	2,663,491
Compressed Air	0.27	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity	196,276
Solid Waste Disposal	25.38	$/Ton, 1,003.963 lb/hr, 8760 hr/yr	100,437
Total Annual Direct Operating Costs (DC			**3,566,235**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	934,650
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	467,325
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	467,325
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	4,411,217
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**6,336,046**
Total Annual Cost (Annualized Capital Cost + Operating Cost			**9,902,280**
Pollutant Removed (tons/yr			**4,397**
Cost per ton of PM Removed			**2,252**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipmen		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	12110	Number
Total Rep Parts Cost	477,625	Cost adjusted for freight & sales tax
Installation Labor	35,858	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**513,483**	
Annualized Cost	**284,003**	

Total Cost Replacement Parts (Bags) **513,483**

Design Flow	623,100	dscfm	708068 scfm
	114	Temp Deg F	
	12%	% Moisture	
	756,855	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	7200	kW-hr	56,766,646	2,663,491	$/kW-hr, 7,200.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1513.71	Mscfm	716,045	196,276	$/Mscf, 1,513.7 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.502	ton/hr	3,957	100,437	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 1,003.963 lb/hr, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	12109.68004	bags	2 yr life	284,003	$/bag, 12,109.7 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculatioı

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
1004	lb/hr	-	MMBtu/hr	NA	**4397**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.4**	Currently assumes 95%.
Emission Reduction T/yı					**4,397**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	756,855	6	0.65	7200.2	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**2,575,826**
Instrumentation	10%	of control device cost (A)	257,583
Sales Taxes	6.0%	of control device cost (A)	154,550
Freight	5%	of control device cost (A)	128,791
Purchased Equipment Total (B)	21%		**3,116,750**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	374,010
Handling & erection	40%	of purchased equip cost (B)	1,246,700
Electrical	1%	of purchased equip cost (B)	31,168
Piping	30%	of purchased equip cost (B)	935,025
Insulation	1%	of purchased equip cost (B)	31,168
Painting	1%	of purchased equip cost (B)	31,168
Installation Total	85%		**2,649,238**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**5,765,988**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	311,675
Construction & field expenses	10%	of purchased equip cost (B)	311,675
Construction fee	10%	of purchased equip cost (B)	311,675
Start-up	1%	of purchased equip cost (B)	31,168
Performance test	1%	of purchased equip cost (B)	31,168
Contingencies	3%	of purchased equip cost (B)	93,503
Total Indirect Capital Costs, IC	35%		**1,090,863**
Total Capital Investment (TCI) = DC + IC			**6,856,850**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	137,137
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	976,261
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,362,401**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,453,964**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**5,088**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations **Annual hours of operation:** **8,760**
Utilization Rate: **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%		
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.53	lb Lime/lb SO2	568.62	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B)	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**21,876,176**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**24,967,739**
Pollutant Removed (tons/yr)[B]			**1,465**
Cost per ton of SO2 Removed			**17,042**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. 90%**	**Emis Rate T/yr**	**Currently assumes 80%.**
				90%	**163**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1465.0**	Assuming 90% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65 lb/hr SO2	2.50 lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65 lb/hr SO2	1.53 lb Lime/lb SO2	568.62	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**2,575,826**
Instrumentation	10%	of control device cost (A)	257,583
Sales Taxes	6.0%	of control device cost (A)	154,550
Freight	5%	of control device cost (A)	128,791
Purchased Equipment Total (B)	21%		**3,116,750**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	374,010
Handling & erection	40%	of purchased equip cost (B)	1,246,700
Electrical	1%	of purchased equip cost (B)	31,168
Piping	30%	of purchased equip cost (B)	935,025
Insulation	1%	of purchased equip cost (B)	31,168
Painting	1%	of purchased equip cost (B)	31,168
Installation Total	85%		**2,649,238**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**5,765,988**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	311,675
Construction & field expenses	10%	of purchased equip cost (B)	311,675
Construction fee	10%	of purchased equip cost (B)	311,675
Start-up	1%	of purchased equip cost (B)	31,168
Performance test	1%	of purchased equip cost (B)	31,168
Contingencies	3%	of purchased equip cost (B)	93,503
Total Indirect Capital Costs, IC	35%		**1,090,863**
Total Capital Investment (TCI) = DC + IC			**6,856,850**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	137,137
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	68,569
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	976,261
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**4,362,401**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**7,453,964**
Pollutant Removed (tons/yr)[B]			**1,628**
Cost per ton of SO2 Removed			**4,580**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	
				99.99%		**Currently assumes 80%.**
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1627.7**	Assuming 99.99% control.

	Flow acfm	∆ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65 lb/hr SO2	2.50	lb NaOH/lb SO2	929.12 lb/hr Caustic
Lime Use	371.65 lb/hr SO2	1.53	lb Lime/lb SO2	568.62 lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Purchased Equipment Costs - Absorber + packing + auxillary equipment, EC			**38,650,338**
Instrumentation	10%	of control device cost (A)	3,865,034
Sales Taxes	6.0%	of control device cost (A)	2,319,020
Freight	5%	of control device cost (A)	1,932,517
Purchased Equipment Total (B)	21%		**46,766,909**
Installation			
Foundations & supports	12%	of purchased equip cost (B)	5,612,029
Handling & erection	40%	of purchased equip cost (B)	18,706,764
Electrical	1%	of purchased equip cost (B)	467,669
Piping	30%	of purchased equip cost (B)	14,030,073
Insulation	1%	of purchased equip cost (B)	467,669
Painting	1%	of purchased equip cost (B)	467,669
Installation Total	85%		**39,751,873**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost, DC			**86,518,782**
Indirect Capital Costs			
Engineering, supervision	10%	of purchased equip cost (B)	4,676,691
Construction & field expenses	10%	of purchased equip cost (B)	4,676,691
Construction fee	10%	of purchased equip cost (B)	4,676,691
Start-up	1%	of purchased equip cost (B)	467,669
Performance test	1%	of purchased equip cost (B)	467,669
Contingencies	3%	of purchased equip cost (B)	1,403,007
Total Indirect Capital Costs, IC	35%		**16,368,418**
Total Capital Investment (TCI) = DC + IC			**102,887,200**
OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	25.38	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	12,506
Supervisor	15%	of oper labor costs 15%	1,876
Operating Materials			
Reagent #1	284	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	1,041,140
Reagent #2	NA	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime	-
Catalyst	NA		-
Wastewater Treatment	1.52	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity	981,382
Maintenance			
Maintenance Labor	17.77	1/2 hr per shift	9,727
Maintenance Materials	100%	of maintenance labor costs	9,727
Electricity - Fan, Pump	0.05	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity	1,035,205
Total Annual Direct Operating Costs			**3,091,563**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	20,302
Administration (2% total capital costs)	2%	of total capital costs (TCI)	2,057,744
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	1,028,872
Capital Recovery	14.24%	for a 10- year equipment life and a 7% interest rate	14,648,823
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**21,876,176**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**24,967,739**
Pollutant Removed (tons/yr)[B]			**1,628**
Cost per ton of SO2 Removed			**15,340**

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BART ANALYSIS 2004
WET FLUE GAS DESULFURIZATION

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	10	years
CRF	0.1424	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	623,100	dscfm	708068	scfm
	114	Temp Deg F		
	12%	% Moisture		
	756,855	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	0.5	hr/8 hr shift	493	12,506	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	15%	of Op.			NA	1,876	15% of Operator Costs
Maint Labor	17.77	Hr	0.5	hr/8 hr shift	493	4,125	$/Hr, 0.5 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2798.5	kW-hr	22,063,188	1,035,205	$/kW-hr, 2,798 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.20	Mgal	1,362.3	gpm	644,441	130,851	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.25	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	284.26	Ton	929.12	lb/hr	3,663	1,041,140	$/Ton, 929.1 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2 (Lime)	300	Ton	0.000	lb/hr	0	0	$/Ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, Lime
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
WW Treat	1.52	Mgal	1,362.3	gpm	644,441	981,382	$/Mgal, 1,362.3 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost facto

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.64	lb/MMBtu	650	MMBTU/HR	NA	**1,627.81**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	
				99.99%		**Currently assumes 80%.**
				99.99%	**0**	Basis:8760 hr/yr, 90.0% of capacity
Emission Reduction T/yr					**1627.7**	Assuming 99.99% control.

	Flow acfm	Δ P in H2O	Blower Eff	Motor Eff	kW	
Blower	681,170	12	0.55	0.7	2484.1	OAQPS Cost Cont Manual 6th ed - Eq 1.48
	Flow gpm	P ft H2O	Pump Eff	Motor Eff		
Circ Pump	6,812	125	0.8	0.7	285.8	OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O WW Disch	1,362.3	62.5	0.8	0.7	28.6	OAQPS Cost Cont Manual 6th ed - Eq 1.49

Caustic Use	371.65	lb/hr SO2	2.50	lb NaOH/lb SO2	929.12	lb/hr Caustic
Lime Use	371.65	lb/hr SO2	1.53	lb Lime/lb SO2	568.62	lb/hr Lime

Water Makeup Rate/WW Disch = 20% of circulating water rate
Utility use rates basis: 8760 hr/yr, 90.0% of capacity

PM Boilers

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**974,026**
Instrumentation	10%	of control device cost (A)	97,403
IN Sales Taxes	6%	of control device cost (A)	58,442
Freight	5%	of control device cost (A)	48,701
Purchased Equipment Total (B)	21%		**1,178,571**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	47,143
Handling & erection	50%	of purchased equip cost (B)	589,286
Electrical	8%	of purchased equip cost (B)	94,286
Piping	1%	of purchased equip cost (B)	11,786
Insulation for ductwork	2%	of purchased equip cost (B)	23,571
Painting	2%	of purchased equip cost (B)	23,571
Direct Installation Costs			**789,643**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**1,968,214**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	235,714
Construction & field expenses	20%	of purchased equip cost (B)	235,714
Constractor fees	10%	of purchased equip cost (B)	117,857
Start-up	1%	of purchased equip cost (B)	11,786
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	23,571
Contingencies	3%	of purchased equip cost (B)	35,357
Total Indirect Capital Costs	57%		**660,000**
Total Capital Investment (TCI) = DC + IC			**2,628,214**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	19,149
Maintenance Materials	1%	of purchased equipment costs	11,786
Utilities			
Electricity	0.05	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity	228,313
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	1,844
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**298,110**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	35,819
Administration (2% total capital costs)	2%	of total capital costs (TCI)	52,564
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	26,282
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	26,282
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	248,085
Total Indirect Operating Costs			**389,033**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**687,143**
Pollutant Removed (tons/yr)[B]			**80.7**
Cost per ton of PM Removed			**8,513**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	80,237	ft^2 collector area		9,408	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	617	kW-hr	4,866,011	228,313	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.009	ton/hr	73	1,844	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/Mmbtu	650	MMBTU/HR	NA	**90**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**9.0**	Currently assumes 90%.
Emission Reduction T/yr					**80.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	80,237	155.7	2	4	159.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	264,000	acfm
Area #2	**80236.6**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**12,662,338**
Instrumentation	10%	of control device cost (A)	1,266,234
IN Sales Taxes	6%	of control device cost (A)	759,740
Freight	5%	of control device cost (A)	633,117
Purchased Equipment Total (B)	21%		**15,321,429**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	612,857
Handling & erection	50%	of purchased equip cost (B)	7,660,714
Electrical	8%	of purchased equip cost (B)	1,225,714
Piping	1%	of purchased equip cost (B)	153,214
Insulation for ductwork	2%	of purchased equip cost (B)	306,429
Painting	2%	of purchased equip cost (B)	306,429
Direct Installation Costs			**10,265,357**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**25,586,786**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	3,064,286
Construction & field expenses	20%	of purchased equip cost (B)	3,064,286
Constractor fees	10%	of purchased equip cost (B)	1,532,143
Start-up	1%	of purchased equip cost (B)	153,214
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	306,429
Contingencies	3%	of purchased equip cost (B)	459,643
Total Indirect Capital Costs	57%		**8,580,000**
Total Capital Investment (TCI) = DC + IC			**34,166,786**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	136,032
Maintenance Materials	1%	of purchased equipment costs	153,214
Utilities			
Electricity	0.05	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity	228,313
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	1,844
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**556,422**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	190,806
Administration (2% total capital costs)	2%	of total capital costs (TCI)	683,336
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	341,668
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	341,668
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	3,225,103
Total Indirect Operating Costs			**4,782,581**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,339,003**
Pollutant Removed (tons/yr)[B]			**80.7**
Cost per ton of PM Removed			**66,148**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations **Annual hours of operation: 8,760**
Utilization Rate: 90.0%

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	80,237	ft^2 collector area		9,408	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	617	kW-hr	4,866,011	228,313	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.009	ton/hr	73	1,844	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/Mmbtu	650	MMBTU/HR	NA	**90**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**9.0**	Currently assumes 90%.
Emission Reduction T/yr					**80.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	80,237	155.7	2	4	159.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	264,000	acfm
Area #2	**80236.6**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**974,026**
Instrumentation	10%	of control device cost (A)	97,403
IN Sales Taxes	6%	of control device cost (A)	58,442
Freight	5%	of control device cost (A)	48,701
Purchased Equipment Total (B)	21%		**1,178,571**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	47,143
Handling & erection	50%	of purchased equip cost (B)	589,286
Electrical	8%	of purchased equip cost (B)	94,286
Piping	1%	of purchased equip cost (B)	11,786
Insulation for ductwork	2%	of purchased equip cost (B)	23,571
Painting	2%	of purchased equip cost (B)	23,571
Direct Installation Costs			**789,643**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**1,968,214**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	235,714
Construction & field expenses	20%	of purchased equip cost (B)	235,714
Constractor fees	10%	of purchased equip cost (B)	117,857
Start-up	1%	of purchased equip cost (B)	11,786
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	23,571
Contingencies	3%	of purchased equip cost (B)	35,357
Total Indirect Capital Costs	57%		**660,000**
Total Capital Investment (TCI) = DC + IC			**2,628,214**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	19,149
Maintenance Materials	1%	of purchased equipment costs	11,786
Utilities			
Electricity	0.05	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity	228,313
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	2,048
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**298,315**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	35,819
Administration (2% total capital costs)	2%	of total capital costs (TCI)	52,564
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	26,282
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	26,282
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	248,085
Total Indirect Operating Costs			**389,033**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**687,348**
Pollutant Removed (tons/yr)[B]			**89.7**
Cost per ton of PM Removed			**7,665**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	80,237	ft^2 collector area		9,408	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	617	kW-hr	4,866,011	228,313	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.010	ton/hr	81	2,048	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/Mmbtu	650	MMBTU/HR	NA	**90**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**89.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	80,237	155.7	2	4	159.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	264,000	acfm
Area #2	**80236.6**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**12,662,338**
Instrumentation	10%	of control device cost (A)	1,266,234
IN Sales Taxes	6%	of control device cost (A)	759,740
Freight	5%	of control device cost (A)	633,117
Purchased Equipment Total (B)	21%		**15,321,429**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	612,857
Handling & erection	50%	of purchased equip cost (B)	7,660,714
Electrical	8%	of purchased equip cost (B)	1,225,714
Piping	1%	of purchased equip cost (B)	153,214
Insulation for ductwork	2%	of purchased equip cost (B)	306,429
Painting	2%	of purchased equip cost (B)	306,429
Direct Installation Costs			**10,265,357**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**25,586,786**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	3,064,286
Construction & field expenses	20%	of purchased equip cost (B)	3,064,286
Constractor fees	10%	of purchased equip cost (B)	1,532,143
Start-up	1%	of purchased equip cost (B)	153,214
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	306,429
Contingencies	3%	of purchased equip cost (B)	459,643
Total Indirect Capital Costs	57%		**8,580,000**
Total Capital Investment (TCI) = DC + IC			**34,166,786**

OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	136,032
Maintenance Materials	1%	of purchased equipment costs	153,214
Utilities			
Electricity	0.05	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity	228,313
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	2,048
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**556,626**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	190,806
Administration (2% total capital costs)	2%	of total capital costs (TCI)	683,336
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	341,668
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	341,668
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	3,225,103
Total Indirect Operating Costs			**4,782,581**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,339,207**
Pollutant Removed (tons/yr)[B]			**89.7**
Cost per ton of PM Removed			**59,542**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	80,237	ft^2 collector area		9,408	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	617	kW-hr	4,866,011	228,313	$/kW-hr, 617.2 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.010	ton/hr	81	2,048	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.04	lb/Mmbtu	650	MMBTU/HR	NA	**90**	

Controlled Emission Rate

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**89.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	80,237	155.7	2	4	159.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	264,000	acfm
Area #2	**80236.6**	**ft2**

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**597,758**
Instrumentation	10%	of control device cost (A)	59,776
IN Sales Taxes	6%	of control device cost (A)	35,866
Freight	5%	of control device cost (A)	29,888
Purchased Equipment Total (B)	21%		**723,288**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	28,932
Handling & erection	50%	of purchased equip cost (B)	361,644
Electrical	8%	of purchased equip cost (B)	57,863
Piping	1%	of purchased equip cost (B)	7,233
Insulation for ductwork	7%	of purchased equip cost (B)	50,630
Painting	4%	of purchased equip cost (B)	28,932
Installation Total	74%		**535,233**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**1,258,521**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	72,329
Construction and field expense	20%	of purchased equip cost (B)	144,658
Contractor fees	10%	of purchased equip cost (B)	72,329
Startup	1%	of purchased equip cost (B)	7,233
Performance test	1%	of purchased equip cost (B)	7,233
Contingencies	3%	of purchased equip cost (B)	21,699
Total Indirect Capital Costs	45%		**325,479**
Total Capital Investment (TCI) = DC + IC			**1,584,000**

OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			344,907
Utilities			
Electricity	0.05	\$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity	1,789,068
Compressed Air	0.27	\$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity	131,839
Solid Waste Disposal	25.38	\$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	1,946
Total Annual Direct Operating Costs (DC)			**2,360,307**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	31,680
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	15,840
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	15,840
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	149,518
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**268,407**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,628,714**
Pollutant Removed (tons/yr)			**85**
Cost per ton of PM Removed			**30,855**

Operating Cost Calculati

Item
Op Labor
Supervisor
Maint Labor
Maint Mtls
Utilities, Reagents, Waste
Electricity
Natural Gas
Water
Comp Air
Reagent #1(Caustic)
Reagent #2
SW Disposal
Haz W Disp
WW Treat
Catalyst
Rep Parts

Uncontrolled Emission R

Emission Factor

0.04

Controlled Emission Rate

Perf Guarantee

Emission Reduction T/yı

Electrical Consumption Re

Blower

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	8134.07821	Number
Total Rep Parts Cost	320,821	Cost adjusted for freight & sales tax
Installation Labor	24,086	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**344,907**	
Annualized Cost	**190,765**	

Total Cost Replacement Parts (Bags) **344,907**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

ions **Annual hours of operation:** **8,760**
Utilization Rate: **90.0%**

Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
NA				NA	NA	Calc'd as % of labor costs
17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
NA				NA	NA	Calc'd as % of labor costs
e Management & Replacements						
0.047	kW-hr	4836	kW-hr	38,130,185	1,789,068	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity
4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
0.27	Mscf	1016.76	Mscfm	480,968	131,839	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity
300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
25.38	Ton	0.010	ton/hr	77	1,946	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
35.53299492	bag	8134.07821	bags	2 yr life	190,765	$/bag, 8,134.1 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

ate

Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
lb/MMBtu	650	MMBTU/HR	NA	**90**	

e

Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
			95.00%	**4.5**	Currently assumes 95%.
r				**85**	

equirements Kilowatts

Flow acfm	D P in H2O	Blower-Motor Eff	kW	
508,380	6	0.65	4836.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**7,471,980**
Instrumentation	10%	of control device cost (A)	747,198
IN Sales Taxes	6%	of control device cost (A)	448,319
Freight	5%	of control device cost (A)	373,599
Purchased Equipment Total (B)	21%		**9,041,096**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	361,644
Handling & erection	50%	of purchased equip cost (B)	4,520,548
Electrical	8%	of purchased equip cost (B)	723,288
Piping	1%	of purchased equip cost (B)	90,411
Insulation for ductwork	7%	of purchased equip cost (B)	632,877
Painting	4%	of purchased equip cost (B)	361,644
Installation Total	74%		**6,690,411**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**15,731,507**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	904,110
Construction and field expense	20%	of purchased equip cost (B)	1,808,219
Contractor fees	10%	of purchased equip cost (B)	904,110
Startup	1%	of purchased equip cost (B)	90,411
Performance test	1%	of purchased equip cost (B)	90,411
Contingencies	3%	of purchased equip cost (B)	271,233
Total Indirect Capital Costs	45%		**4,068,493**
Total Capital Investment (TCI) = DC + IC			**19,800,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			344,907
Utilities			
Electricity	0.05	\$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity	1,789,068
Compressed Air	0.27	\$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity	131,839
Solid Waste Disposal	25.38	\$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	1,946
Total Annual Direct Operating Costs (DC)			**2,360,307**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,000
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,000
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,000
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,868,980
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,716,508**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,076,815**
Pollutant Removed (tons/yr)			**85**
Cost per ton of PM Removed			**59,589**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	8134.07821	Number
Total Rep Parts Cost	320,821	Cost adjusted for freight & sales tax
Installation Labor	24,086	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**344,907**	
Annualized Cost	**190,765**	

Total Cost Replacement Parts (Bags) **344,907**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	4836	kW-hr	38,130,185	1,789,068	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1016.76	Mscfm	480,968	131,839	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.010	ton/hr	77	1,946	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	8134.07821	bags	2 yr life	190,765	$/bag, 8,134.1 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/MMBtu	650	MMBTU/HR	NA	**90**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**4.5**	Currently assumes 95%.
Emission Reduction T/yr					**85**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	508,380	6	0.65	4836.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**597,758**
Instrumentation	10%	of control device cost (A)	59,776
IN Sales Taxes	6%	of control device cost (A)	35,866
Freight	5%	of control device cost (A)	29,888
Purchased Equipment Total (B)	21%		**723,288**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	28,932
Handling & erection	50%	of purchased equip cost (B)	361,644
Electrical	8%	of purchased equip cost (B)	57,863
Piping	1%	of purchased equip cost (B)	7,233
Insulation for ductwork	7%	of purchased equip cost (B)	50,630
Painting	4%	of purchased equip cost (B)	28,932
Installation Total	74%		**535,233**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**1,258,521**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	72,329
Construction and field expense	20%	of purchased equip cost (B)	144,658
Contractor fees	10%	of purchased equip cost (B)	72,329
Startup	1%	of purchased equip cost (B)	7,233
Performance test	1%	of purchased equip cost (B)	7,233
Contingencies	3%	of purchased equip cost (B)	21,699
Total Indirect Capital Costs	45%		**325,479**
Total Capital Investment (TCI) = DC + IC			**1,584,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			344,907
Utilities			
Electricity	0.05	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity	1,789,068
Compressed Air	0.27	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity	131,839
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	2,048
Total Annual Direct Operating Costs (DC)			**2,360,409**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	31,680
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	15,840
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	15,840
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	149,518
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**268,407**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,628,816**
Pollutant Removed (tons/yr)			**90**
Cost per ton of PM Removed			**29,316**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	8134.07821	Number
Total Rep Parts Cost	320,821	Cost adjusted for freight & sales tax
Installation Labor	24,086	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**344,907**	
Annualized Cost	**190,765**	

Total Cost Replacement Parts (Bags) **344,907**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	4836	kW-hr	38,130,185	1,789,068	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1016.76	Mscfm	480,968	131,839	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.010	ton/hr	81	2,048	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	8134.07821	bags	2 yr life	190,765	$/bag, 8,134.1 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/MMBtu	650	MMBTU/HR	NA	**90**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 95%.
Emission Reduction T/yr					**90**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	508,380	6	0.65	4836.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**7,471,980**
Instrumentation	10%	of control device cost (A)	747,198
IN Sales Taxes	6%	of control device cost (A)	448,319
Freight	5%	of control device cost (A)	373,599
Purchased Equipment Total (B)	21%		**9,041,096**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	361,644
Handling & erection	50%	of purchased equip cost (B)	4,520,548
Electrical	8%	of purchased equip cost (B)	723,288
Piping	1%	of purchased equip cost (B)	90,411
Insulation for ductwork	7%	of purchased equip cost (B)	632,877
Painting	4%	of purchased equip cost (B)	361,644
Installation Total	74%		**6,690,411**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**15,731,507**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	904,110
Construction and field expense	20%	of purchased equip cost (B)	1,808,219
Contractor fees	10%	of purchased equip cost (B)	904,110
Startup	1%	of purchased equip cost (B)	90,411
Performance test	1%	of purchased equip cost (B)	90,411
Contingencies	3%	of purchased equip cost (B)	271,233
Total Indirect Capital Costs	45%		**4,068,493**
Total Capital Investment (TCI) = DC + IC			**19,800,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			344,907
Utilities			
Electricity	0.05	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity	1,789,068
Compressed Air	0.27	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity	131,839
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	2,048
Total Annual Direct Operating Costs (DC)			**2,360,409**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	396,000
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	198,000
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	198,000
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,868,980
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**2,716,508**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,076,918**
Pollutant Removed (tons/yr)			**90**
Cost per ton of PM Removed			**56,617**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	8134.07821	Number
Total Rep Parts Cost	320,821	Cost adjusted for freight & sales tax
Installation Labor	24,086	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**344,907**	
Annualized Cost	**190,765**	

Total Cost Replacement Parts (Bags) **344,907**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	4836	kW-hr	38,130,185	1,789,068	$/kW-hr, 4,836.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	1016.76	Mscfm	480,968	131,839	$/Mscf, 1,016.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.010	ton/hr	81	2,048	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	8134.07821	bags	2 yr life	190,765	$/bag, 8,134.1 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/MMBtu	650	MMBTU/HR	NA	**90**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 95%.
Emission Reduction T/yr					**90**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	508,380	6	0.65	4836.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**2,045,455**
Instrumentation	10%	of control device cost (A)	204,545
IN Sales Taxes	6%	of control device cost (A)	122,727
Freight	5%	of control device cost (A)	102,273
Purchased Equipment Total (B)	21%		**2,475,000**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	99,000
Handling & erection	50%	of purchased equip cost (B)	1,237,500
Electrical	8%	of purchased equip cost (B)	198,000
Piping	1%	of purchased equip cost (B)	24,750
Insulation for ductwork	2%	of purchased equip cost (B)	49,500
Painting	2%	of purchased equip cost (B)	49,500
Direct Installation Costs			**1,658,250**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**4,133,250**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	495,000
Construction & field expenses	20%	of purchased equip cost (B)	495,000
Constractor fees	10%	of purchased equip cost (B)	247,500
Start-up	1%	of purchased equip cost (B)	24,750
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	49,500
Contingencies	3%	of purchased equip cost (B)	74,250
Total Indirect Capital Costs	57%		**1,386,000**
Total Capital Investment (TCI) = DC + IC			**5,519,250**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	38,572
Maintenance Materials	1%	of purchased equipment costs	24,750
Utilities			
Electricity	0.05	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity	308,130
Water	0.22	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	483,410
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	3,295,974
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**4,187,854**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,252
Administration (2% total capital costs)	2%	of total capital costs (TCI)	110,385
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	55,193
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	55,193
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	520,978
Total Indirect Operating Costs			**797,000**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,984,855**
Pollutant Removed (tons/yr)			**80.7**
Cost per ton of PM Removed			**61,761**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	154,510	ft^2 collector area		18,118	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	833	kW-hr	6,567,135	308,130	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	4575	gpm	2,164,356	483,410	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	4575	gpm	2,164,356	3,295,974	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	650	MMBTU/HR	NA	**89.68**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**9.0**	Currently assumes 90%.
Emission Reduction T/yr					**80.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	4575	60	0.8	0.9	71.7	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	154,510	299.7	2	4	303.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	20.48	lb/hr SO2	2.50	lb NaOH/lb SO2	0.026	T/hr Caustic
Lime Use	20.48	lb/hr SO2	1.53	lb Lime/lb SO2	0.016	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	508,380	acfm
Area #2	**154510.0**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**19,870,130**
Instrumentation	10%	of control device cost (A)	1,987,013
IN Sales Taxes	6%	of control device cost (A)	1,192,208
Freight	5%	of control device cost (A)	993,506
Purchased Equipment Total (B)	21%		**24,042,857**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	961,714
Handling & erection	50%	of purchased equip cost (B)	12,021,429
Electrical	8%	of purchased equip cost (B)	1,923,429
Piping	1%	of purchased equip cost (B)	240,429
Insulation for ductwork	2%	of purchased equip cost (B)	480,857
Painting	2%	of purchased equip cost (B)	480,857
Direct Installation Costs			**16,108,714**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**40,151,571**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	4,808,571
Construction & field expenses	20%	of purchased equip cost (B)	4,808,571
Constractor fees	10%	of purchased equip cost (B)	2,404,286
Start-up	1%	of purchased equip cost (B)	240,429
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	480,857
Contingencies	3%	of purchased equip cost (B)	721,286
Total Indirect Capital Costs	57%		**13,464,000**
Total Capital Investment (TCI) = DC + IC			**53,615,571**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	216,819
Maintenance Materials	1%	of purchased equipment costs	240,429
Utilities			
Electricity	0.05	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity	308,130
Water	0.22	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	483,410
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	3,295,974
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**4,581,780**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	291,607
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,072,311
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	536,156
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	536,156
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	5,060,931
Total Indirect Operating Costs			**7,497,161**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,078,941**
Pollutant Removed (tons/yr)			**80.7**
Cost per ton of PM Removed			**149,654**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	154,510	ft^2 collector area		18,118	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	833	kW-hr	6,567,135	308,130	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	4575	gpm	2,164,356	483,410	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	4575	gpm	2,164,356	3,295,974	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	650	MMBTU/HR	NA	**89.68**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**9.0**	Currently assumes 90%.
Emission Reduction T/yr					**80.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	4575	60	0.8	0.9	71.7	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	154,510	299.7	2	4	303.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	20.48	lb/hr SO2	2.50	lb NaOH/lb SO2	0.026	T/hr Caustic
Lime Use	20.48	lb/hr SO2	1.53	lb Lime/lb SO2	0.016	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	508,380	acfm
Area #2	**154510.0**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**2,045,455**
Instrumentation	10%	of control device cost (A)	204,545
IN Sales Taxes	6%	of control device cost (A)	122,727
Freight	5%	of control device cost (A)	102,273
Purchased Equipment Total (B)	21%		**2,475,000**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	99,000
Handling & erection	50%	of purchased equip cost (B)	1,237,500
Electrical	8%	of purchased equip cost (B)	198,000
Piping	1%	of purchased equip cost (B)	24,750
Insulation for ductwork	2%	of purchased equip cost (B)	49,500
Painting	2%	of purchased equip cost (B)	49,500
Direct Installation Costs			**1,658,250**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**4,133,250**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	495,000
Construction & field expenses	20%	of purchased equip cost (B)	495,000
Constractor fees	10%	of purchased equip cost (B)	247,500
Start-up	1%	of purchased equip cost (B)	24,750
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	49,500
Contingencies	3%	of purchased equip cost (B)	74,250
Total Indirect Capital Costs	57%		**1,386,000**
Total Capital Investment (TCI) = DC + IC			**5,519,250**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	\$/ft2 collector area; \$5775 if < 50,000 ft2	38,572
Maintenance Materials	1%	of purchased equipment costs	24,750
Utilities			
Electricity	0.05	\$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity	308,130
Water	0.22	\$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	483,410
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	\$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	3,295,974
Reagent (Caustic)	280.00	\$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**4,187,854**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,252
Administration (2% total capital costs)	2%	of total capital costs (TCI)	110,385
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	55,193
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	55,193
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	520,978
Total Indirect Operating Costs			**797,000**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**4,984,855**
Pollutant Removed (tons/yr)			**89.7**
Cost per ton of PM Removed			**55,590**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000 scfm
	450	Temp Deg F	
	12%	% Moisture	
	508,380	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	154,510	ft^2 collector area		18,118	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	833	kW-hr	6,567,135	308,130	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	4575	gpm	2,164,356	483,410	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	4575	gpm	2,164,356	3,295,974	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	650	MMBTU/HR	NA	**89.68**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**89.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	4575	60	0.8	0.9	71.7	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	154,510	299.7	2	4	303.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	20.48	lb/hr SO2	2.50	lb NaOH/lb SO2	0.026	T/hr Caustic
Lime Use	20.48	lb/hr SO2	1.53	lb Lime/lb SO2	0.016	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	508,380	acfm
Area #2	**154510.0**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**19,870,130**
Instrumentation	10%	of control device cost (A)	1,987,013
IN Sales Taxes	6%	of control device cost (A)	1,192,208
Freight	5%	of control device cost (A)	993,506
Purchased Equipment Total (B)	21%		**24,042,857**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	961,714
Handling & erection	50%	of purchased equip cost (B)	12,021,429
Electrical	8%	of purchased equip cost (B)	1,923,429
Piping	1%	of purchased equip cost (B)	240,429
Insulation for ductwork	2%	of purchased equip cost (B)	480,857
Painting	2%	of purchased equip cost (B)	480,857
Direct Installation Costs			**16,108,714**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**40,151,571**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	4,808,571
Construction & field expenses	20%	of purchased equip cost (B)	4,808,571
Constractor fees	10%	of purchased equip cost (B)	2,404,286
Start-up	1%	of purchased equip cost (B)	240,429
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	480,857
Contingencies	3%	of purchased equip cost (B)	721,286
Total Indirect Capital Costs	57%		**13,464,000**
Total Capital Investment (TCI) = DC + IC			**53,615,571**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	216,819
Maintenance Materials	1%	of purchased equipment costs	240,429
Utilities			
Electricity	0.05	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity	308,130
Water	0.22	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	483,410
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity	3,295,974
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**4,581,780**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	291,607
Administration (2% total capital costs)	2%	of total capital costs (TCI)	1,072,311
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	536,156
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	536,156
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	5,060,931
Total Indirect Operating Costs			**7,497,161**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**12,078,941**
Pollutant Removed (tons/yr)			**89.7**
Cost per ton of PM Removed			**134,702**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	264,000	dscfm	300000	scfm
	450	Temp Deg F		
	12%	% Moisture		
	508,380	acfm		

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	154,510	ft^2 collector area		18,118	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	833	kW-hr	6,567,135	308,130	$/kW-hr, 833.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	4575	gpm	2,164,356	483,410	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	4575	gpm	2,164,356	3,295,974	$/Mgal, 4,575.4 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	650	MMBTU/HR	NA	**89.68**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**89.7**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	508,380	5	0.65		457.5	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	4575	60	0.8	0.9	71.7	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	154,510	299.7	2	4	303.7	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	20.48	lb/hr SO2	2.50	lb NaOH/lb SO2	0.026	T/hr Caustic
Lime Use	20.48	lb/hr SO2	1.53	lb Lime/lb SO2	0.016	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	508,380	acfm
Area #2	**154510.0**	**ft2**

PM Furnaces

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**402,155**
Instrumentation	10%	of control device cost (A)	40,215
IN Sales Taxes	6%	of control device cost (A)	24,129
Freight	5%	of control device cost (A)	20,108
Purchased Equipment Total (B)	21%		**486,607**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	19,464
Handling & erection	50%	of purchased equip cost (B)	243,304
Electrical	8%	of purchased equip cost (B)	38,929
Piping	1%	of purchased equip cost (B)	4,866
Insulation for ductwork	2%	of purchased equip cost (B)	9,732
Painting	2%	of purchased equip cost (B)	9,732
Direct Installation Costs			**326,027**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**812,634**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	97,321
Construction & field expenses	20%	of purchased equip cost (B)	97,321
Constractor fees	10%	of purchased equip cost (B)	48,661
Start-up	1%	of purchased equip cost (B)	4,866
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	9,732
Contingencies	3%	of purchased equip cost (B)	14,598
Total Indirect Capital Costs	57%		**272,500**
Total Capital Investment (TCI) = DC + IC			**1,085,134**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	8,147
Maintenance Materials	1%	of purchased equipment costs	4,866
Utilities			
Electricity	0.05	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity	152,729
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	380
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**203,140**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	25,066
Administration (2% total capital costs)	2%	of total capital costs (TCI)	21,703
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,851
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,851
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	102,429
Total Indirect Operating Costs			**170,901**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**374,041**
Pollutant Removed (tons/yr)[B]			**16.6**
Cost per ton of PM Removed			**22,480**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations					**Annual hours of operation:**	**8,760**		
					Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**	
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	
Supervisor	NA				NA	NA	Calc'd as % of labor costs	
Maint Labor	0.117	$/ft^2 collector	33,128	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2	
Maint Mtls	NA				NA	1%	of purchased equipment costs	
Utilities, Reagents, Waste Management & Replacements								
Electricity	0.047	kW-hr	413	kW-hr	3,255,084	152,729	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity	
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity	
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity	
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	
SW Disposal	25.38	Ton	0.002	ton/hr	15	380	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity	
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity	
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity	

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/Mmbtu	134	MMBTU/HR	NA	**18**	

Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**1.8**	Currently assumes 90%.
Emission Reduction T/yr					**16.6**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	33,128	64.3	2	4	68.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	109,000	acfm
Area #2	**33128.0**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**5,228,011**
Instrumentation	10%	of control device cost (A)	522,801
IN Sales Taxes	6%	of control device cost (A)	313,681
Freight	5%	of control device cost (A)	261,401
Purchased Equipment Total (B)	21%		**6,325,893**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	253,036
Handling & erection	50%	of purchased equip cost (B)	3,162,946
Electrical	8%	of purchased equip cost (B)	506,071
Piping	1%	of purchased equip cost (B)	63,259
Insulation for ductwork	2%	of purchased equip cost (B)	126,518
Painting	2%	of purchased equip cost (B)	126,518
Direct Installation Costs			**4,238,348**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**10,564,241**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	1,265,179
Construction & field expenses	20%	of purchased equip cost (B)	1,265,179
Constractor fees	10%	of purchased equip cost (B)	632,589
Start-up	1%	of purchased equip cost (B)	63,259
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	126,518
Contingencies	3%	of purchased equip cost (B)	189,777
Total Indirect Capital Costs	57%		**3,542,500**
Total Capital Investment (TCI) = DC + IC			**14,106,741**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	56,405
Maintenance Materials	1%	of purchased equipment costs	63,259
Utilities			
Electricity	0.05	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity	152,729
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	380
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**309,791**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	89,057
Administration (2% total capital costs)	2%	of total capital costs (TCI)	282,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	141,067
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	141,067
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,331,577
Total Indirect Operating Costs			**1,984,903**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,294,695**
Pollutant Removed (tons/yr)[B]			**16.6**
Cost per ton of PM Removed			**137,909**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	33,128	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	413	kW-hr	3,255,084	152,729	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.002	ton/hr	15	380	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/Mmbtu	134	MMBTU/HR	NA	**18**	

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**1.8**	Currently assumes 90%.
Emission Reduction T/yr					**16.6**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	33,128	64.3	2	4	68.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	109,000	acfm
Area #2	**33128.0**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**402,155**
Instrumentation	10%	of control device cost (A)	40,215
IN Sales Taxes	6%	of control device cost (A)	24,129
Freight	5%	of control device cost (A)	20,108
Purchased Equipment Total (B)	21%		**486,607**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	19,464
Handling & erection	50%	of purchased equip cost (B)	243,304
Electrical	8%	of purchased equip cost (B)	38,929
Piping	1%	of purchased equip cost (B)	4,866
Insulation for ductwork	2%	of purchased equip cost (B)	9,732
Painting	2%	of purchased equip cost (B)	9,732
Direct Installation Costs			**326,027**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**812,634**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	97,321
Construction & field expenses	20%	of purchased equip cost (B)	97,321
Constractor fees	10%	of purchased equip cost (B)	48,661
Start-up	1%	of purchased equip cost (B)	4,866
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	9,732
Contingencies	3%	of purchased equip cost (B)	14,598
Total Indirect Capital Costs	57%		**272,500**
Total Capital Investment (TCI) = DC + IC			**1,085,134**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	8,147
Maintenance Materials	1%	of purchased equipment costs	4,866
Utilities			
Electricity	0.05	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity	152,729
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	422
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**203,182**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	25,066
Administration (2% total capital costs)	2%	of total capital costs (TCI)	21,703
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	10,851
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	10,851
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	102,429
Total Indirect Operating Costs			**170,901**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**374,083**
Pollutant Removed (tons/yr)[B]			**18.5**
Cost per ton of PM Removed			**20,236**

Capital Recovery Factors	
Primary Installation	
Interest Rate	
Equipment Life	
CRF	

Catalyst Replacement Cost	
Catalyst Life	
CRF	
Catalyst cost per unit	
Amount Required	
Catalyst Cost	
Installation Labor	
Total Installed Cost	
Annualized Cost	

Replacement Parts & Equipment	
Equipment Life	
CRF	
Rep part cost per unit	
Amount Required	
Total Rep Parts Cost	
Installation Labor	
Total Installed Cost	
Annualized Cost	

Total Cost Replacement Parts & Ca

Design Flow	109,000
	1200
	12%
	382,893

Operating Cost Calculations

Item	**Unit Cost $**	**Unit of Measure**
Op Labor	25.38	Hr
Supervisor	NA	
Maint Labor	0.117	$/ft^2 collector
Maint Mtls	NA	
Utilities, Reagents, Waste Management & Replacements		
Electricity	0.047	kW-hr
Natural Gas	4.24	Mft^3
Water	0.22	Mgal
Comp Air	0.27	Mscf
Reagent #1(Caustic)	280	Ton
Reagent #2	300	Ton
SW Disposal	25.38	Ton
Haz W Disp	273	Ton
WW Treat	1.5	Mgal
Catalyst	650	ft^3
Rep Parts	33.72	$/bag

Uncontrolled Emission Rate

Emission Factor	**Unit of Measure**	**Flow Rate**
0.04	lb/Mmbtu	134

Controlled Emission Rate

Perf Guarantee	**Unit of Measure**	**Flow Rate**

Emission Reduction T/yr

Electrical Consumption Requirements

	Flow acfm
Blower	382,893
	Flow gpm
Pump 1	NA
Pump 2	NA
	Area sqft
ESP	33,128

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	109,000	acfm
Area #2	**33128.0**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

7.0%	
20	years
0.0944	

2	years
0.5531	
650	$/ft^3
0	ft^3
0	Cost adjusted for freight & sales tax
0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
0	
0	

2	
0.5531	
33.72	$ each
0	Number
0	Cost adjusted for freight & sales tax
0	10 min per bag (13 hr total) Labor at $29.65/hr
0	
0	

talyst **0**

dscfm	123864 scfm
Temp Deg F	
% Moisture	
acfm	

	Annual hours of operation:		**8,760**	
	Utilization Rate:		**90.0%**	
Use Rate	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
		NA	NA	Calc'd as % of labor costs
33,128	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
		NA	1%	of purchased equipment costs
413	kW-hr	3,255,084	152,729	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity
0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
0.002	ton/hr	17	422	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Unit of Measure	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
MMBTU/HR	NA	**18**	

Unit of Measure	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
	99.99%	**0.0**	Currently assumes 99.99%.
		18.5	

Kilowatts

D P in H2O	Blower Eff		kW	
5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
D P ft H2O	**Pump Eff**	**Motor Eff**		
60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
TR pwr	**# Hoppers**	**Htr Pwr**		
64.3	2	4	68.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**5,228,011**
Instrumentation	10%	of control device cost (A)	522,801
IN Sales Taxes	6%	of control device cost (A)	313,681
Freight	5%	of control device cost (A)	261,401
Purchased Equipment Total (B)	21%		**6,325,893**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	253,036
Handling & erection	50%	of purchased equip cost (B)	3,162,946
Electrical	8%	of purchased equip cost (B)	506,071
Piping	1%	of purchased equip cost (B)	63,259
Insulation for ductwork	2%	of purchased equip cost (B)	126,518
Painting	2%	of purchased equip cost (B)	126,518
Direct Installation Costs			**4,238,348**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**10,564,241**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	1,265,179
Construction & field expenses	20%	of purchased equip cost (B)	1,265,179
Constractor fees	10%	of purchased equip cost (B)	632,589
Start-up	1%	of purchased equip cost (B)	63,259
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	126,518
Contingencies	3%	of purchased equip cost (B)	189,777
Total Indirect Capital Costs	57%		**3,542,500**
Total Capital Investment (TCI) = DC + IC			**14,106,741**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	56,405
Maintenance Materials	1%	of purchased equipment costs	63,259
Utilities			
Electricity	0.05	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity	152,729
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr	422
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**309,834**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	89,057
Administration (2% total capital costs)	2%	of total capital costs (TCI)	282,135
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	141,067
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	141,067
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,331,577
Total Indirect Operating Costs			**1,984,903**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,294,737**
Pollutant Removed (tons/yr)[B]			**18.5**
Cost per ton of PM Removed			**124,133**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	33,128	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	413	kW-hr	3,255,084	152,729	$/kW-hr, 412.9 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.002	ton/hr	17	422	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/Mmbtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/Mmbtu	134	MMBTU/HR	NA	**18**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**18.5**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	33,128	64.3	2	4	68.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	109,000	acfm
Area #2	**33128.0**	**ft2**

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**246,802**
Instrumentation	10%	of control device cost (A)	24,680
IN Sales Taxes	6%	of control device cost (A)	14,808
Freight	5%	of control device cost (A)	12,340
Purchased Equipment Total (B)	21%		**298,630**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	11,945
Handling & erection	50%	of purchased equip cost (B)	149,315
Electrical	8%	of purchased equip cost (B)	23,890
Piping	1%	of purchased equip cost (B)	2,986
Insulation for ductwork	7%	of purchased equip cost (B)	20,904
Painting	4%	of purchased equip cost (B)	11,945
Installation Total	74%		**220,986**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**519,616**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	29,863
Construction and field expense	20%	of purchased equip cost (B)	59,726
Contractor fees	10%	of purchased equip cost (B)	29,863
Startup	1%	of purchased equip cost (B)	2,986
Performance test	1%	of purchased equip cost (B)	2,986
Contingencies	3%	of purchased equip cost (B)	8,959
Total Indirect Capital Costs	45%		**134,384**
Total Capital Investment (TCI) = DC + IC			**654,000**

OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			259,771
Utilities			
Electricity	0.05	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity	1,347,461
Compressed Air	0.27	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity	99,296
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	401
Total Annual Direct Operating Costs (DC)			**1,799,477**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	13,080
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,540
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,540
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	61,733
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**143,421**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,942,898**
Pollutant Removed (tons/yr)			**18**
Cost per ton of PM Removed			**110,621**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	6126.29084	Number
Total Rep Parts Cost	241,631	Cost adjusted for freight & sales tax
Installation Labor	18,140	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**259,771**	
Annualized Cost	**143,677**	

Total Cost Replacement Parts (Bags) **259,771**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760** — **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	3643	kW-hr	28,718,263	1,347,461	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	765.79	Mscfm	362,248	99,296	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.002	ton/hr	16	401	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	6126.29084	bags	2 yr life	143,677	$/bag, 6,126.3 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/MMBtu	134	MMBTU/HR	NA	**18**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**0.9**	Currently assumes 95%.
Emission Reduction T/yr					**18**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	382,893	6	0.65	3642.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**3,085,022**
Instrumentation	10%	of control device cost (A)	308,502
IN Sales Taxes	6%	of control device cost (A)	185,101
Freight	5%	of control device cost (A)	154,251
Purchased Equipment Total (B)	21%		**3,732,877**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	149,315
Handling & erection	50%	of purchased equip cost (B)	1,866,438
Electrical	8%	of purchased equip cost (B)	298,630
Piping	1%	of purchased equip cost (B)	37,329
Insulation for ductwork	7%	of purchased equip cost (B)	261,301
Painting	4%	of purchased equip cost (B)	149,315
Installation Total	74%		**2,762,329**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**6,495,205**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	373,288
Construction and field expense	20%	of purchased equip cost (B)	746,575
Contractor fees	10%	of purchased equip cost (B)	373,288
Startup	1%	of purchased equip cost (B)	37,329
Performance test	1%	of purchased equip cost (B)	37,329
Contingencies	3%	of purchased equip cost (B)	111,986
Total Indirect Capital Costs	45%		**1,679,795**
Total Capital Investment (TCI) = DC + IC			**8,175,000**

OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			259,771
Utilities			
Electricity	0.05	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity	1,347,461
Compressed Air	0.27	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity	99,296
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	401
Total Annual Direct Operating Costs (DC)			**1,799,477**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	163,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	81,750
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	81,750
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	771,662
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,154,190**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,953,667**
Pollutant Removed (tons/yr)			**18**
Cost per ton of PM Removed			**168,170**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	6126.29084	Number
Total Rep Parts Cost	241,631	Cost adjusted for freight & sales tax
Installation Labor	18,140	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**259,771**	
Annualized Cost	**143,677**	

Total Cost Replacement Parts (Bags) **259,771**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	3643	kW-hr	28,718,263	1,347,461	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	765.79	Mscfm	362,248	99,296	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.002	ton/hr	16	401	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	6126.29084	bags	2 yr life	143,677	$/bag, 6,126.3 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/MMBtu	134	MMBTU/HR	NA	**18**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**0.9**	Currently assumes 95%.
Emission Reduction T/yr					**18**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	382,893	6	0.65	3642.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**246,802**
Instrumentation	10%	of control device cost (A)	24,680
IN Sales Taxes	6%	of control device cost (A)	14,808
Freight	5%	of control device cost (A)	12,340
Purchased Equipment Total (B)	21%		**298,630**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	11,945
Handling & erection	50%	of purchased equip cost (B)	149,315
Electrical	8%	of purchased equip cost (B)	23,890
Piping	1%	of purchased equip cost (B)	2,986
Insulation for ductwork	7%	of purchased equip cost (B)	20,904
Painting	4%	of purchased equip cost (B)	11,945
Installation Total	74%		**220,986**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**519,616**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	29,863
Construction and field expense	20%	of purchased equip cost (B)	59,726
Contractor fees	10%	of purchased equip cost (B)	29,863
Startup	1%	of purchased equip cost (B)	2,986
Performance test	1%	of purchased equip cost (B)	2,986
Contingencies	3%	of purchased equip cost (B)	8,959
Total Indirect Capital Costs	45%		**134,384**
Total Capital Investment (TCI) = DC + IC			**654,000**

OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			259,771
Utilities			
Electricity	0.05	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity	1,347,461
Compressed Air	0.27	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity	99,296
Solid Waste Disposal	25.38	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	422
Total Annual Direct Operating Costs (DC)			**1,799,498**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	13,080
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,540
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,540
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	61,733
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**143,421**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,942,919**
Pollutant Removed (tons/yr)			**18**
Cost per ton of PM Removed			**105,101**

Operating Cost Calculati

Item
Op Labor
Supervisor
Maint Labor
Maint Mtls
Utilities, Reagents, Waste
Electricity
Natural Gas
Water
Comp Air
Reagent #1(Caustic)
Reagent #2
SW Disposal
Haz W Disp
WW Treat
Catalyst
Rep Parts

Uncontrolled Emission R
Emission Factor
0.04
Controlled Emission Rate
Perf Guarantee

Emission Reduction T/yr

Electrical Consumption Re

Blower

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	6126.29084	Number
Total Rep Parts Cost	241,631	Cost adjusted for freight & sales tax
Installation Labor	18,140	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**259,771**	
Annualized Cost	**143,677**	

Total Cost Replacement Parts (Bags) **259,771**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

ions **Annual hours of operation:** **8,760**
Utilization Rate: **90.0%**

Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
NA				NA	NA	Calc'd as % of labor costs
17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
NA				NA	NA	Calc'd as % of labor costs
e Management & Replacements						
0.047	kW-hr	3643	kW-hr	28,718,263	1,347,461	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity
4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
0.27	Mscf	765.79	Mscfm	362,248	99,296	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity
300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
25.38	Ton	0.002	ton/hr	17	422	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
35.53299492	bag	6126.29084	bags	2 yr life	143,677	$/bag, 6,126.3 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

ate

Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
lb/MMBtu	134	MMBTU/HR	NA	**18**	

e

Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
			99.99%	**0.0**	Currently assumes 95%.
r				**18**	

equirements Kilowatts

Flow acfm	D P in H2O	Blower-Motor Eff	kW	
382,893	6	0.65	3642.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**3,085,022**
Instrumentation	10%	of control device cost (A)	308,502
IN Sales Taxes	6%	of control device cost (A)	185,101
Freight	5%	of control device cost (A)	154,251
Purchased Equipment Total (B)	21%		**3,732,877**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	149,315
Handling & erection	50%	of purchased equip cost (B)	1,866,438
Electrical	8%	of purchased equip cost (B)	298,630
Piping	1%	of purchased equip cost (B)	37,329
Insulation for ductwork	7%	of purchased equip cost (B)	261,301
Painting	4%	of purchased equip cost (B)	149,315
Installation Total	74%		**2,762,329**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**6,495,205**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	373,288
Construction and field expense	20%	of purchased equip cost (B)	746,575
Contractor fees	10%	of purchased equip cost (B)	373,288
Startup	1%	of purchased equip cost (B)	37,329
Performance test	1%	of purchased equip cost (B)	37,329
Contingencies	3%	of purchased equip cost (B)	111,986
Total Indirect Capital Costs	45%		**1,679,795**
Total Capital Investment (TCI) = DC + IC			**8,175,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			259,771
Utilities			
Electricity	0.05	\$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity	1,347,461
Compressed Air	0.27	\$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity	99,296
Solid Waste Disposal	25.38	\$/Ton, 0.035 lb/MMBtu, 8760 hr/yr	422
Total Annual Direct Operating Costs (DC)			**1,799,498**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	163,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	81,750
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	81,750
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	771,662
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,154,190**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,953,688**
Pollutant Removed (tons/yr)			**18**
Cost per ton of PM Removed			**159,779**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	6126.29084	Number
Total Rep Parts Cost	241,631	Cost adjusted for freight & sales tax
Installation Labor	18,140	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**259,771**	
Annualized Cost	**143,677**	

Total Cost Replacement Parts (Bags) **259,771**

Design Flow	109,000	dscfm	123864 scfm
	1200	Temp Deg F	
	12%	% Moisture	
	382,893	acfm	

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	3643	kW-hr	28,718,263	1,347,461	$/kW-hr, 3,642.6 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	765.79	Mscfm	362,248	99,296	$/Mscf, 765.8 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.002	ton/hr	17	422	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lb/MMBtu, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	6126.29084	bags	2 yr life	143,677	$/bag, 6,126.3 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lb/MMBtu	134	MMBTU/HR	NA	**18**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 95%.
Emission Reduction T/yr					**18**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	382,893	6	0.65	3642.6	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**844,525**
Instrumentation	10%	of control device cost (A)	84,452
IN Sales Taxes	6%	of control device cost (A)	50,671
Freight	5%	of control device cost (A)	42,226
Purchased Equipment Total (B)	21%		**1,021,875**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	40,875
Handling & erection	50%	of purchased equip cost (B)	510,938
Electrical	8%	of purchased equip cost (B)	81,750
Piping	1%	of purchased equip cost (B)	10,219
Insulation for ductwork	2%	of purchased equip cost (B)	20,438
Painting	2%	of purchased equip cost (B)	20,438
Direct Installation Costs			**684,656**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**1,706,531**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	204,375
Construction & field expenses	20%	of purchased equip cost (B)	204,375
Constractor fees	10%	of purchased equip cost (B)	102,188
Start-up	1%	of purchased equip cost (B)	10,219
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	20,438
Contingencies	3%	of purchased equip cost (B)	30,656
Total Indirect Capital Costs	57%		**572,250**
Total Capital Investment (TCI) = DC + IC			**2,278,781**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	22,091
Maintenance Materials	1%	of purchased equipment costs	10,219
Utilities			
Electricity	0.05	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity	232,437
Water	0.22	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	364,086
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	2,482,407
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**3,148,259**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	36,644
Administration (2% total capital costs)	2%	of total capital costs (TCI)	45,576
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	22,788
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	22,788
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	215,101
Total Indirect Operating Costs			**342,897**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,491,156**
Pollutant Removed (tons/yr)			**16.6**
Cost per ton of PM Removed			**209,815**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/$ft^3$
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/$ft^2$ collector	116,371	ft^2 collector area		13,646	$/$ft^2$ collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	628	kW-hr	4,953,910	232,437	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	3446	gpm	1,630,114	364,086	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	3446	gpm	1,630,114	2,482,407	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	134	MMBTU/HR	NA	**18.49**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**1.8**	Currently assumes 90%.
Emission Reduction T/yr					**16.6**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	3446	60	0.8	0.9	54.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	116,371	225.8	2	4	229.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	4.22	lb/hr SO2	2.50	lb NaOH/lb SO2	0.005	T/hr Caustic
Lime Use	4.22	lb/hr SO2	1.53	lb Lime/lb SO2	0.003	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	382,893	acfm
Area #2	**116371.3**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**8,203,955**
Instrumentation	10%	of control device cost (A)	820,396
IN Sales Taxes	6%	of control device cost (A)	492,237
Freight	5%	of control device cost (A)	410,198
Purchased Equipment Total (B)	21%		**9,926,786**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	397,071
Handling & erection	50%	of purchased equip cost (B)	4,963,393
Electrical	8%	of purchased equip cost (B)	794,143
Piping	1%	of purchased equip cost (B)	99,268
Insulation for ductwork	2%	of purchased equip cost (B)	198,536
Painting	2%	of purchased equip cost (B)	198,536
Direct Installation Costs			**6,650,946**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**16,577,732**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	1,985,357
Construction & field expenses	20%	of purchased equip cost (B)	1,985,357
Constractor fees	10%	of purchased equip cost (B)	992,679
Start-up	1%	of purchased equip cost (B)	99,268
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	198,536
Contingencies	3%	of purchased equip cost (B)	297,804
Total Indirect Capital Costs	57%		**5,559,000**
Total Capital Investment (TCI) = DC + IC			**22,136,732**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	95,685
Maintenance Materials	1%	of purchased equipment costs	99,268
Utilities			
Electricity	0.05	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity	232,437
Water	0.22	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	364,086
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	2,482,407
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**3,310,903**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	134,231
Administration (2% total capital costs)	2%	of total capital costs (TCI)	442,735
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	221,367
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	221,367
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	2,089,551
Total Indirect Operating Costs			**3,109,251**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,420,154**
Pollutant Removed (tons/yr)			**16.6**
Cost per ton of PM Removed			**385,846**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	116,371	ft^2 collector area		13,646	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	628	kW-hr	4,953,910	232,437	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	3446	gpm	1,630,114	364,086	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	3446	gpm	1,630,114	2,482,407	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	134	MMBTU/HR	NA	**18.49**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**1.8**	Currently assumes 90%.
Emission Reduction T/yr					**16.6**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff		kW	
Blower	382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	3446	60	0.8	0.9	54.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	116,371	225.8	2	4	229.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	4.22	lb/hr SO2	2.50	lb NaOH/lb SO2	0.005	T/hr Caustic
Lime Use	4.22	lb/hr SO2	1.53	lb Lime/lb SO2	0.003	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	382,893	acfm
Area #2	**116371.3**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**844,525**
Instrumentation	10%	of control device cost (A)	84,452
IN Sales Taxes	6%	of control device cost (A)	50,671
Freight	5%	of control device cost (A)	42,226
Purchased Equipment Total (B)	21%		**1,021,875**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	40,875
Handling & erection	50%	of purchased equip cost (B)	510,938
Electrical	8%	of purchased equip cost (B)	81,750
Piping	1%	of purchased equip cost (B)	10,219
Insulation for ductwork	2%	of purchased equip cost (B)	20,438
Painting	2%	of purchased equip cost (B)	20,438
Direct Installation Costs			**684,656**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**1,706,531**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	204,375
Construction & field expenses	20%	of purchased equip cost (B)	204,375
Constractor fees	10%	of purchased equip cost (B)	102,188
Start-up	1%	of purchased equip cost (B)	10,219
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	20,438
Contingencies	3%	of purchased equip cost (B)	30,656
Total Indirect Capital Costs	57%		**572,250**
Total Capital Investment (TCI) = DC + IC			**2,278,781**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	22,091
Maintenance Materials	1%	of purchased equipment costs	10,219
Utilities			
Electricity	0.05	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity	232,437
Water	0.22	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	364,086
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	2,482,407
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**3,148,259**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	36,644
Administration (2% total capital costs)	2%	of total capital costs (TCI)	45,576
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	22,788
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	22,788
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	215,101
Total Indirect Operating Costs			**342,897**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**3,491,156**
Pollutant Removed (tons/yr)			**18.5**
Cost per ton of PM Removed			**188,853**

Capital Recovery I
Primary Installatio
Interest Rate
Equipment Life
CRF

Catalyst Replacem
Catalyst Life
CRF
Catalyst cost per un
Amount Required
Catalyst Cost
Installation Labor
Total Installed Cost
Annualized Cost

Replacement Parts
Equipment Life
CRF
Rep part cost per ur
Amount Required
Total Rep Parts Cos
Installation Labor
Total Installed Cost
Annualized Cost

Total Cost Replace

Design Flow

Operating Cost Calculations

Item	**Unit Cost $**
Op Labor	25.38
Supervisor	NA
Maint Labor	0.12
Maint Mtls	NA
Utilities, Reagents, Waste Management & Rep	
Electricity	0.047
Natural Gas	4.24
Water	0.22
Comp Air	0.27
Reagent #1(Caustic)	280
Reagent #2	300
SW Disposal	25
Haz W Disp	273
WW Treat	1.52
Catalyst	650
Rep Parts	33.72

Uncontrolled Emission Rate	
Emission Factor	**Unit of Measure**
0.04	lbs/Mmbtu
Controlled Emission Rate	
Perf Guarantee	**Unit of Measure**
Emission Reduction T/yr	

Electrical Consump

Blower

Pump 1
Pump 2

ESP

Caustic Use	4.22
Lime Use	4.22

Estimate Area (ft2)	
Area #1	48503
Flow #1	159588
Flow #2	382,893
Area #2	**116371.3**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Factors
on

	7.0%	
	20	years
	0.0944	

nent Cost

	2	years
	0.5531	
nit	650	$/ft^3
	0	ft^3
	0	Cost adjusted for freight & sales tax
	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
t	**0**	
	0	

s & Equipment

	2	
	0.5531	
nit	33.72	$ each
	0	Number
st	0	Cost adjusted for freight & sales tax
	0	10 min per bag (13 hr total) Labor at $29.65/hr
t	**0**	
	0	

ement Parts & Catalyst **0**

109,000	dscfm	123864	scfm
1200	Temp Deg F		
12%	% Moisture		
382,893	acfm		

Annual hours of operation: **8,760**
Utilization Rate: **90.0%**

Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
			NA	NA	Calc'd as % of labor costs
$/ft^2 collector	116,371	ft^2 collector area		13,646	$/ft^2 collector area; $5775 if < 50,000 ft^2
			NA	1%	of purchased equipment costs
placements					
kW-hr	628	kW-hr	4,953,910	232,437	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity
Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Mgal	3446	gpm	1,630,114	364,086	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Mgal	3446	gpm	1,630,114	2,482,407	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
134	MMBTU/HR	NA	**18.49**	

Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
		99.99%	**0.0**	Currently assumes 99.99%.
			18.5	

otion Requirements Kilowatts

Flow acfm	D P in H2O	Blower-Motor Eff		kW	
382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
3446	60	0.8	0.9	54.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Area sqft	TR pwr	# Hoppers	Htr Pwr		
116,371	225.8	2	4	229.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

lb/hr SO2	2.50	lb NaOH/lb SO2	0.005	T/hr Caustic
lb/hr SO2	1.53	lb Lime/lb SO2	0.003	T/hr Lime

ft2
acfm
acfm
ft2

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**8,203,955**
Instrumentation	10%	of control device cost (A)	820,396
IN Sales Taxes	6%	of control device cost (A)	492,237
Freight	5%	of control device cost (A)	410,198
Purchased Equipment Total (B)	21%		**9,926,786**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	397,071
Handling & erection	50%	of purchased equip cost (B)	4,963,393
Electrical	8%	of purchased equip cost (B)	794,143
Piping	1%	of purchased equip cost (B)	99,268
Insulation for ductwork	2%	of purchased equip cost (B)	198,536
Painting	2%	of purchased equip cost (B)	198,536
Direct Installation Costs			**6,650,946**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**16,577,732**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	1,985,357
Construction & field expenses	20%	of purchased equip cost (B)	1,985,357
Constructor fees	10%	of purchased equip cost (B)	992,679
Start-up	1%	of purchased equip cost (B)	99,268
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	198,536
Contingencies	3%	of purchased equip cost (B)	297,804
Total Indirect Capital Costs	57%		**5,559,000**
Total Capital Investment (TCI) = DC + IC			**22,136,732**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	95,685
Maintenance Materials	1%	of purchased equipment costs	99,268
Utilities			
Electricity	0.05	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity	232,437
Water	0.22	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	364,086
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity	2,482,407
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**3,310,903**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	134,231
Administration (2% total capital costs)	2%	of total capital costs (TCI)	442,735
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	221,367
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	221,367
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	2,089,551
Total Indirect Operating Costs			**3,109,251**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**6,420,154**
Pollutant Removed (tons/yr)			**18.5**
Cost per ton of PM Removed			**347,296**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	109,000	dscfm	123864	scfm
	1200	Temp Deg F		
	12%	% Moisture		
	382,893	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	116,371	ft^2 collector area		13,646	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	628	kW-hr	4,953,910	232,437	$/kW-hr, 628.3 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	3446	gpm	1,630,114	364,086	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.035 lbs/Mmbtu, 8760 hr/yr
WW Treat	1.52	Mgal	3446	gpm	1,630,114	2,482,407	$/Mgal, 3,446.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.04	lbs/Mmbtu	134	MMBTU/HR	NA	**18.49**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**18.5**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	382,893	5	0.65		344.6	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	3446	60	0.8	0.9	54.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	116,371	225.8	2	4	229.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	4.22	lb/hr SO2	2.50	lb NaOH/lb SO2	0.005	T/hr Caustic
Lime Use	4.22	lb/hr SO2	1.53	lb Lime/lb SO2	0.003	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	382,893	acfm
Area #2	**116371.3**	**ft2**

PM Coke Underfire

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**260,387**
Instrumentation	10%	of control device cost (A)	26,039
IN Sales Taxes	6%	of control device cost (A)	15,623
Freight	5%	of control device cost (A)	13,019
Purchased Equipment Total (B)	21%		**315,068**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	12,603
Handling & erection	50%	of purchased equip cost (B)	157,534
Electrical	8%	of purchased equip cost (B)	25,205
Piping	1%	of purchased equip cost (B)	3,151
Insulation for ductwork	7%	of purchased equip cost (B)	22,055
Painting	4%	of purchased equip cost (B)	12,603
Installation Total	74%		**233,151**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**548,219**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	31,507
Construction and field expense	20%	of purchased equip cost (B)	63,014
Contractor fees	10%	of purchased equip cost (B)	31,507
Startup	1%	of purchased equip cost (B)	3,151
Performance test	1%	of purchased equip cost (B)	3,151
Contingencies	3%	of purchased equip cost (B)	9,452
Total Indirect Capital Costs	45%		**141,781**
Total Capital Investment (TCI) = DC + IC			**690,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			156,848
Utilities			
Electricity	0.05	$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity	813,585
Compressed Air	0.27	$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity	59,954
Solid Waste Disposal	25.38	$/Ton, 0.468 lb/ton, 8760 hr/yr	3,555
Total Annual Direct Operating Costs (DC)			**1,126,489**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	13,800
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,900
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,900
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	65,131
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**148,259**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,274,748**
Pollutant Removed (tons/yr)			**156**
Cost per ton of PM Removed			**8,192**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	3699.00119	Number
Total Rep Parts Cost	145,895	Cost adjusted for freight & sales tax
Installation Labor	10,953	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**156,848**	
Annualized Cost	**86,751**	

Total Cost Replacement Parts (Bags) **156,848**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2199	kW-hr	17,339,838	813,585	$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	462.38	Mscfm	218,722	59,954	$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.018	ton/hr	140	3,555	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	3699.00119	bags	2 yr life	86,751	$/bag, 3,699.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**164**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**8.2**	Currently assumes 95%.
Emission Reduction T/yr					**156**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	231,188	6	0.65	2199.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**3,254,840**
Instrumentation	10%	of control device cost (A)	325,484
IN Sales Taxes	6%	of control device cost (A)	195,290
Freight	5%	of control device cost (A)	162,742
Purchased Equipment Total (B)	21%		**3,938,356**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	157,534
Handling & erection	50%	of purchased equip cost (B)	1,969,178
Electrical	8%	of purchased equip cost (B)	315,068
Piping	1%	of purchased equip cost (B)	39,384
Insulation for ductwork	7%	of purchased equip cost (B)	275,685
Painting	4%	of purchased equip cost (B)	157,534
Installation Total	74%		**2,914,384**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**6,852,740**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	393,836
Construction and field expense	20%	of purchased equip cost (B)	787,671
Contractor fees	10%	of purchased equip cost (B)	393,836
Startup	1%	of purchased equip cost (B)	39,384
Performance test	1%	of purchased equip cost (B)	39,384
Contingencies	3%	of purchased equip cost (B)	118,151
Total Indirect Capital Costs	45%		**1,772,260**
Total Capital Investment (TCI) = DC + IC			**8,625,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			156,848
Utilities			
Electricity	0.05	$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity	813,585
Compressed Air	0.27	$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity	59,954
Solid Waste Disposal	25.38	$/Ton, 0.468 lb/ton, 8760 hr/yr	3,555
Total Annual Direct Operating Costs (DC)			**1,126,489**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	172,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	86,250
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	86,250
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	814,139
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,214,667**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,341,156**
Pollutant Removed (tons/yr)			**156**
Cost per ton of PM Removed			**15,045**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	3699.00119	Number
Total Rep Parts Cost	145,895	Cost adjusted for freight & sales tax
Installation Labor	10,953	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**156,848**	
Annualized Cost	**86,751**	

Total Cost Replacement Parts (Bags) **156,848**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations — **Annual hours of operation:** **8,760**; **Utilization Rate:** **90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2199	kW-hr	17,339,838	813,585	$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	462.38	Mscfm	218,722	59,954	$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.018	ton/hr	140	3,555	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	3699.00119	bags	2 yr life	86,751	$/bag, 3,699.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**164**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				95.00%	**8.2**	Currently assumes 95%.
Emission Reduction T/yr					**156**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	231,188	6	0.65	2199.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**260,387**
Instrumentation	10%	of control device cost (A)	26,039
IN Sales Taxes	6%	of control device cost (A)	15,623
Freight	5%	of control device cost (A)	13,019
Purchased Equipment Total (B)	21%		**315,068**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	12,603
Handling & erection	50%	of purchased equip cost (B)	157,534
Electrical	8%	of purchased equip cost (B)	25,205
Piping	1%	of purchased equip cost (B)	3,151
Insulation for ductwork	7%	of purchased equip cost (B)	22,055
Painting	4%	of purchased equip cost (B)	12,603
Installation Total	74%		**233,151**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**548,219**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	31,507
Construction and field expense	20%	of purchased equip cost (B)	63,014
Contractor fees	10%	of purchased equip cost (B)	31,507
Startup	1%	of purchased equip cost (B)	3,151
Performance test	1%	of purchased equip cost (B)	3,151
Contingencies	3%	of purchased equip cost (B)	9,452
Total Indirect Capital Costs	45%		**141,781**
Total Capital Investment (TCI) = DC + IC			**690,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			156,848
Utilities			
Electricity	0.05	\$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity	813,585
Compressed Air	0.27	\$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity	59,954
Solid Waste Disposal	25.38	\$/Ton, 0.468 lb/ton, 8760 hr/yr	3,741
Total Annual Direct Operating Costs (DC)			**1,126,675**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	13,800
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	6,900
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	6,900
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	65,131
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**148,259**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,274,935**
Pollutant Removed (tons/yr)			**164**
Cost per ton of PM Removed			**7,784**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	3699.00119	Number
Total Rep Parts Cost	145,895	Cost adjusted for freight & sales tax
Installation Labor	10,953	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**156,848**	
Annualized Cost	**86,751**	

Total Cost Replacement Parts (Bags) **156,848**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2199	kW-hr	17,339,838	813,585	$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	462.38	Mscfm	218,722	59,954	$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.019	ton/hr	147	3,741	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	3699.00119	bags	2 yr life	86,751	$/bag, 3,699.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	164	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 95%.
Emission Reduction T/yr					**164**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	231,188	6	0.65	2199.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
FABRIC FILTER

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
Fabric Filter (EC) + bags + auxillary equipment			**3,254,840**
Instrumentation	10%	of control device cost (A)	325,484
IN Sales Taxes	6%	of control device cost (A)	195,290
Freight	5%	of control device cost (A)	162,742
Purchased Equipment Total (B)	21%		**3,938,356**
Direct installation costs			
Foundations & supports	4%	of purchased equip cost (B)	157,534
Handling & erection	50%	of purchased equip cost (B)	1,969,178
Electrical	8%	of purchased equip cost (B)	315,068
Piping	1%	of purchased equip cost (B)	39,384
Insulation for ductwork	7%	of purchased equip cost (B)	275,685
Painting	4%	of purchased equip cost (B)	157,534
Installation Total	74%		**2,914,384**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Cost			**6,852,740**
Indirect Capital Costs			
Engineering	10%	of purchased equip cost (B)	393,836
Construction and field expense	20%	of purchased equip cost (B)	787,671
Contractor fees	10%	of purchased equip cost (B)	393,836
Startup	1%	of purchased equip cost (B)	39,384
Performance test	1%	of purchased equip cost (B)	39,384
Contingencies	3%	of purchased equip cost (B)	118,151
Total Indirect Capital Costs	45%		**1,772,260**
Total Capital Investment (TCI) = DC + IC			**8,625,000**
OPERATING COSTS			
Direct Operating Costs			
Operating Labor	25.38	\$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	50,025
Supervisor	15%	of operator labor costs	7,504
Maintenance Labor	17.77	\$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	17,509
Maintenance Materials	100%	of maintenance labor costs	17,509
Replacement parts, bags			156,848
Utilities			
Electricity	0.05	\$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity	813,585
Compressed Air	0.27	\$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity	59,954
Solid Waste Disposal	25.38	\$/Ton, 0.468 lb/ton, 8760 hr/yr	3,741
Total Annual Direct Operating Costs (DC)			**1,126,675**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	55,528
Administration (2% total capital costs)	2%	of total capital costs (TCI)	172,500
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	86,250
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	86,250
Capital Recovery	9%	for a 20- year equipment life and a 7% interest rate	814,139
Total Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,214,667**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,341,342**
Pollutant Removed (tons/yr)			**164**
Cost per ton of PM Removed			**14,295**

BART ANALYSIS 2004
FABRIC FILTER

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	years
CRF	0.5531	
Rep part cost per unit	35.53	$ each
Amount Required	3699.00119	Number
Total Rep Parts Cost	145,895	Cost adjusted for freight & sales tax
Installation Labor	10,953	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**156,848**	
Annualized Cost	**86,751**	

Total Cost Replacement Parts (Bags) **156,848**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	Comments
Op Labor	25.38	Hr	2	hr/8 hr shift	1,971	50,025	$/Hr, 2.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	17.77	Hr	1	hr/8 hr shift	986	17,509	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Maint Mtls	NA				NA	NA	Calc'd as % of labor costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	2199	kW-hr	17,339,838	813,585	$/kW-hr, 2,199.4 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	462.38	Mscfm	218,722	59,954	$/Mscf, 462.4 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.019	ton/hr	147	3,741	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	35.53299492	bag	3699.00119	bags	2 yr life	86,751	$/bag, 3,699.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate

Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
0.47	lb/ton	700,000	tpy	NA	**164**	

Controlled Emission Rate

Perf Guarantee	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emis Rate T/yr	Comments/Notes
				99.99%	**0.0**	Currently assumes 95%.
Emission Reduction T/yr					**164**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff	kW	
Blower	231,188	6	0.65	2199.4	OAQPS Cost Cont Manual 6th ed - Eq 1.14

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**424,292**
Instrumentation	10%	of control device cost (A)	42,429
IN Sales Taxes	6%	of control device cost (A)	25,457
Freight	5%	of control device cost (A)	21,215
Purchased Equipment Total (B)	21%		**513,393**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	20,536
Handling & erection	50%	of purchased equip cost (B)	256,696
Electrical	8%	of purchased equip cost (B)	41,071
Piping	1%	of purchased equip cost (B)	5,134
Insulation for ductwork	2%	of purchased equip cost (B)	10,268
Painting	2%	of purchased equip cost (B)	10,268
Direct Installation Costs			**343,973**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**857,366**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	102,679
Construction & field expenses	20%	of purchased equip cost (B)	102,679
Constractor fees	10%	of purchased equip cost (B)	51,339
Start-up	1%	of purchased equip cost (B)	5,134
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	10,268
Contingencies	3%	of purchased equip cost (B)	15,402
Total Indirect Capital Costs	57%		**287,500**
Total Capital Investment (TCI) = DC + IC			**1,144,866**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	8,368
Maintenance Materials	1%	of purchased equipment costs	5,134
Utilities			
Electricity	0.05	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity	103,531
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.468 lb/ton, 8760 hr/yr	3,367
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**157,419**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	25,360
Administration (2% total capital costs)	2%	of total capital costs (TCI)	22,897
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	11,449
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	11,449
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	108,067
Total Indirect Operating Costs			**179,222**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**336,640**
Pollutant Removed (tons/yr)[B]			**147.4**
Cost per ton of PM Removed			**2,284**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682	scfm
	490	Temp Deg F		
	12%	% Moisture		
	231,188	acfm		

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	34,952	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	280	kW-hr	2,206,533	103,531	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.017	ton/hr	133	3,367	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**164**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**16.4**	Currently assumes 90%.
Emission Reduction T/yr					**147.4**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	34,952	67.8	2	4	71.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	115,000	acfm
Area #2	**34951.5**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**5,515,791**
Instrumentation	10%	of control device cost (A)	551,579
IN Sales Taxes	6%	of control device cost (A)	330,947
Freight	5%	of control device cost (A)	275,790
Purchased Equipment Total (B)	21%		**6,674,107**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	266,964
Handling & erection	50%	of purchased equip cost (B)	3,337,054
Electrical	8%	of purchased equip cost (B)	533,929
Piping	1%	of purchased equip cost (B)	66,741
Insulation for ductwork	2%	of purchased equip cost (B)	133,482
Painting	2%	of purchased equip cost (B)	133,482
Direct Installation Costs			**4,471,652**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**11,145,759**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	1,334,821
Construction & field expenses	20%	of purchased equip cost (B)	1,334,821
Constractor fees	10%	of purchased equip cost (B)	667,411
Start-up	1%	of purchased equip cost (B)	66,741
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	133,482
Contingencies	3%	of purchased equip cost (B)	200,223
Total Indirect Capital Costs	57%		**3,737,500**
Total Capital Investment (TCI) = DC + IC			**14,883,259**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	59,283
Maintenance Materials	1%	of purchased equipment costs	66,741
Utilities			
Electricity	0.05	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity	103,531
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.468 lb/ton, 8760 hr/yr	3,367
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**269,941**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	92,873
Administration (2% total capital costs)	2%	of total capital costs (TCI)	297,665
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	148,833
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	148,833
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,404,874
Total Indirect Operating Costs			**2,093,078**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,363,019**
Pollutant Removed (tons/yr)[B]			**147.4**
Cost per ton of PM Removed			**16,029**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations				**Annual hours of operation:**		**8,760**	
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	34,952	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	280	kW-hr	2,206,533	103,531	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.017	ton/hr	133	3,367	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**164**	

Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**16.4**	Currently assumes 90%.
Emission Reduction T/yr					**147.4**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	34,952	67.8	2	4	71.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	115,000	acfm
Area #2	**34951.5**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**424,292**
Instrumentation	10%	of control device cost (A)	42,429
IN Sales Taxes	6%	of control device cost (A)	25,457
Freight	5%	of control device cost (A)	21,215
Purchased Equipment Total (B)	21%		**513,393**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	20,536
Handling & erection	50%	of purchased equip cost (B)	256,696
Electrical	8%	of purchased equip cost (B)	41,071
Piping	1%	of purchased equip cost (B)	5,134
Insulation for ductwork	2%	of purchased equip cost (B)	10,268
Painting	2%	of purchased equip cost (B)	10,268
Direct Installation Costs			**343,973**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**857,366**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	102,679
Construction & field expenses	20%	of purchased equip cost (B)	102,679
Constractor fees	10%	of purchased equip cost (B)	51,339
Start-up	1%	of purchased equip cost (B)	5,134
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	10,268
Contingencies	3%	of purchased equip cost (B)	15,402
Total Indirect Capital Costs	57%		**287,500**
Total Capital Investment (TCI) = DC + IC			**1,144,866**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	8,368
Maintenance Materials	1%	of purchased equipment costs	5,134
Utilities			
Electricity	0.05	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity	103,531
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.468 lb/ton, 8760 hr/yr	3,741
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**157,792**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	25,360
Administration (2% total capital costs)	2%	of total capital costs (TCI)	22,897
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	11,449
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	11,449
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	108,067
Total Indirect Operating Costs			**179,222**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**337,014**
Pollutant Removed (tons/yr)[B]			**163.8**
Cost per ton of PM Removed			**2,058**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	34,952	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	280	kW-hr	2,206,533	103,531	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.019	ton/hr	147	3,741	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**164**	

Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**163.8**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	34,952	67.8	2	4	71.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	115,000	acfm
Area #2	**34951.5**	**ft2**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**5,515,791**
Instrumentation	10%	of control device cost (A)	551,579
IN Sales Taxes	6%	of control device cost (A)	330,947
Freight	5%	of control device cost (A)	275,790
Purchased Equipment Total (B)	21%		**6,674,107**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	266,964
Handling & erection	50%	of purchased equip cost (B)	3,337,054
Electrical	8%	of purchased equip cost (B)	533,929
Piping	1%	of purchased equip cost (B)	66,741
Insulation for ductwork	2%	of purchased equip cost (B)	133,482
Painting	2%	of purchased equip cost (B)	133,482
Direct Installation Costs			**4,471,652**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**11,145,759**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	1,334,821
Construction & field expenses	20%	of purchased equip cost (B)	1,334,821
Constractor fees	10%	of purchased equip cost (B)	667,411
Start-up	1%	of purchased equip cost (B)	66,741
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	133,482
Contingencies	3%	of purchased equip cost (B)	200,223
Total Indirect Capital Costs	57%		**3,737,500**
Total Capital Investment (TCI) = DC + IC			**14,883,259**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	59,283
Maintenance Materials	1%	of purchased equipment costs	66,741
Utilities			
Electricity	0.05	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity	103,531
Water	NA		-
Solid Waste Disposal	25.38	$/Ton, 0.468 lb/ton, 8760 hr/yr	3,741
Wastewater Treatment	NA		-
Total Annual Direct Operating Costs, DC			**270,315**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	92,873
Administration (2% total capital costs)	2%	of total capital costs (TCI)	297,665
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	148,833
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	148,833
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	1,404,874
Total Indirect Operating Costs			**2,093,078**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,363,392**
Pollutant Removed (tons/yr)[B]			**163.8**
Cost per ton of PM Removed			**14,430**

BART ANALYSIS 2004
DRY ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.117	$/ft^2 collector	34,952	ft^2 collector area		4,125	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	280	kW-hr	2,206,533	103,531	$/kW-hr, 279.9 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0.0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25.38	Ton	0.019	ton/hr	147	3,741	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	164	

Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**163.8**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	NA	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	34,952	67.8	2	4	71.8	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	115,000	acfm
Area #2	**34951.5**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**891,012**
Instrumentation	10%	of control device cost (A)	89,101
IN Sales Taxes	6%	of control device cost (A)	53,461
Freight	5%	of control device cost (A)	44,551
Purchased Equipment Total (B)	21%		**1,078,125**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	43,125
Handling & erection	50%	of purchased equip cost (B)	539,063
Electrical	8%	of purchased equip cost (B)	86,250
Piping	1%	of purchased equip cost (B)	10,781
Insulation for ductwork	2%	of purchased equip cost (B)	21,563
Painting	2%	of purchased equip cost (B)	21,563
Direct Installation Costs			**722,344**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**1,800,469**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	215,625
Construction & field expenses	20%	of purchased equip cost (B)	215,625
Constractor fees	10%	of purchased equip cost (B)	107,813
Start-up	1%	of purchased equip cost (B)	10,781
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	21,563
Contingencies	3%	of purchased equip cost (B)	32,344
Total Indirect Capital Costs	57%		**603,750**
Total Capital Investment (TCI) = DC + IC			**2,404,219**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	17,149
Maintenance Materials	1%	of purchased equipment costs	10,781
Utilities			
Electricity	0.05	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity	140,930
Water	0.22	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	219,832
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	1,498,856
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**1,924,567**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	34,017
Administration (2% total capital costs)	2%	of total capital costs (TCI)	48,084
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	24,042
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	24,042
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	226,941
Total Indirect Operating Costs			**357,127**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,281,694**
Pollutant Removed (tons/yr)			**147.4**
Cost per ton of PM Removed			**15,478**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:		**90.0%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	70,264	ft^2 collector area		8,239	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	381	kW-hr	3,003,623	140,930	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	2081	gpm	984,249	219,832	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.52	Mgal	2081	gpm	984,249	1,498,856	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**163.80**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**16.4**	Currently assumes 90%.
Emission Reduction T/yr					**147.4**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	2081	60	0.8	0.9	32.6	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	70,264	136.3	2	4	140.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	37.40	lb/hr SO2	2.50	lb NaOH/lb SO2	0.047	T/hr Caustic
Lime Use	37.40	lb/hr SO2	1.53	lb Lime/lb SO2	0.029	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	231,188	acfm
Area #2	**70264.0**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**8,655,549**
Instrumentation	10%	of control device cost (A)	865,555
IN Sales Taxes	6%	of control device cost (A)	519,333
Freight	5%	of control device cost (A)	432,777
Purchased Equipment Total (B)	21%		**10,473,214**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	418,929
Handling & erection	50%	of purchased equip cost (B)	5,236,607
Electrical	8%	of purchased equip cost (B)	837,857
Piping	1%	of purchased equip cost (B)	104,732
Insulation for ductwork	2%	of purchased equip cost (B)	209,464
Painting	2%	of purchased equip cost (B)	209,464
Direct Installation Costs			**7,017,054**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**17,490,268**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	2,094,643
Construction & field expenses	20%	of purchased equip cost (B)	2,094,643
Constractor fees	10%	of purchased equip cost (B)	1,047,321
Start-up	1%	of purchased equip cost (B)	104,732
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	209,464
Contingencies	3%	of purchased equip cost (B)	314,196
Total Indirect Capital Costs	57%		**5,865,000**
Total Capital Investment (TCI) = DC + IC			**23,355,268**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	94,795
Maintenance Materials	1%	of purchased equipment costs	104,732
Utilities			
Electricity	0.05	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity	140,930
Water	0.22	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	219,832
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	1,498,856
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**2,096,164**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	136,975
Administration (2% total capital costs)	2%	of total capital costs (TCI)	467,105
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	233,553
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	233,553
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	2,204,572
Total Indirect Operating Costs			**3,275,758**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,371,921**
Pollutant Removed (tons/yr)			**147.4**
Cost per ton of PM Removed			**36,440**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682	scfm
	490	Temp Deg F		
	12%	% Moisture		
	231,188	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	70,264	ft^2 collector area		8,239	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	381	kW-hr	3,003,623	140,930	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	2081	gpm	984,249	219,832	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.52	Mgal	2081	gpm	984,249	1,498,856	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**163.80**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				90%	**16.4**	Currently assumes 90%.
Emission Reduction T/yr					**147.4**	

Electrical Consumption Requirements Kilowatts

	Flow acfm	D P in H2O	Blower-Motor Eff		kW	
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	2081	60	0.8	0.9	32.6	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	70,264	136.3	2	4	140.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	37.40	lb/hr SO2	2.50	lb NaOH/lb SO2	0.047	T/hr Caustic
Lime Use	37.40	lb/hr SO2	1.53	lb Lime/lb SO2	0.029	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	231,188	acfm
Area #2	**70264.0**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**891,012**
Instrumentation	10%	of control device cost (A)	89,101
IN Sales Taxes	6%	of control device cost (A)	53,461
Freight	5%	of control device cost (A)	44,551
Purchased Equipment Total (B)	21%		**1,078,125**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	43,125
Handling & erection	50%	of purchased equip cost (B)	539,063
Electrical	8%	of purchased equip cost (B)	86,250
Piping	1%	of purchased equip cost (B)	10,781
Insulation for ductwork	2%	of purchased equip cost (B)	21,563
Painting	2%	of purchased equip cost (B)	21,563
Direct Installation Costs			**722,344**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**1,800,469**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	215,625
Construction & field expenses	20%	of purchased equip cost (B)	215,625
Constractor fees	10%	of purchased equip cost (B)	107,813
Start-up	1%	of purchased equip cost (B)	10,781
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	21,563
Contingencies	3%	of purchased equip cost (B)	32,344
Total Indirect Capital Costs	57%		**603,750**
Total Capital Investment (TCI) = DC + IC			**2,404,219**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	17,149
Maintenance Materials	1%	of purchased equipment costs	10,781
Utilities			
Electricity	0.05	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity	140,930
Water	0.22	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	219,832
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	1,498,856
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**1,924,567**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	34,017
Administration (2% total capital costs)	2%	of total capital costs (TCI)	48,084
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	24,042
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	24,042
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	226,941
Total Indirect Operating Costs			**357,127**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**2,281,694**
Pollutant Removed (tons/yr)			**163.8**
Cost per ton of PM Removed			**13,931**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682	scfm
	490	Temp Deg F		
	12%	% Moisture		
	231,188	acfm		

Operating Cost Calculations — **Annual hours of operation: 8,760** — **Utilization Rate: 90.0%**

Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	70,264	ft^2 collector area		8,239	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	381	kW-hr	3,003,623	140,930	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	2081	gpm	984,249	219,832	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.52	Mgal	2081	gpm	984,249	1,498,856	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**163.80**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**163.8**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	2081	60	0.8	0.9	32.6	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	70,264	136.3	2	4	140.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	37.40	lb/hr SO2	2.50	lb NaOH/lb SO2	0.047	T/hr Caustic
Lime Use	37.40	lb/hr SO2	1.53	lb Lime/lb SO2	0.029	T/hr Lime

Estimate Area (ft2)

Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	231,188	acfm
Area #2	**70264.0**	**ft2**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

CAPITAL COSTS			
Direct Capital Costs			
Purchased Equipment (1)			
ESP + auxillary equipment			**8,655,549**
Instrumentation	10%	of control device cost (A)	865,555
IN Sales Taxes	6%	of control device cost (A)	519,333
Freight	5%	of control device cost (A)	432,777
Purchased Equipment Total (B)	21%		**10,473,214**
Direct Installation Costs			
Foundations & supports	4%	of purchased equip cost (B)	418,929
Handling & erection	50%	of purchased equip cost (B)	5,236,607
Electrical	8%	of purchased equip cost (B)	837,857
Piping	1%	of purchased equip cost (B)	104,732
Insulation for ductwork	2%	of purchased equip cost (B)	209,464
Painting	2%	of purchased equip cost (B)	209,464
Direct Installation Costs			**7,017,054**
Site Preparation, as required		Site Specific	NA
Buildings, as required		Site Specific	NA
Total Direct Capital Costs, DC	67%		**17,490,268**
Indirect Capital Costs			
Engineering	20%	of purchased equip cost (B)	2,094,643
Construction & field expenses	20%	of purchased equip cost (B)	2,094,643
Constractor fees	10%	of purchased equip cost (B)	1,047,321
Start-up	1%	of purchased equip cost (B)	104,732
Performance Test	1%	of purchased equip cost (B)	
Model Study	2%	of purchased equip cost (B)	209,464
Contingencies	3%	of purchased equip cost (B)	314,196
Total Indirect Capital Costs	57%		**5,865,000**
Total Capital Investment (TCI) = DC + IC			**23,355,268**
OPERATING COSTS			
Direct Operating Costs			
Operator	25.38	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity	25,013
Supervisor	15%	of operator costs	3,752
Coordinator	33%	of operator costs	8,254
Operating materials			
Maintenance Labor	0.1173	$/ft2 collector area; $5775 if < 50,000 ft2	94,795
Maintenance Materials	1%	of purchased equipment costs	104,732
Utilities			
Electricity	0.05	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity	140,930
Water	0.22	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	219,832
Solid Waste Disposal	NA		-
Wastewater Treatment	1.52	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity	1,498,856
Reagent (Caustic)	280.00	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH	-
Total Annual Direct Operating Costs, DC			**2,096,164**
Indirect Operating Costs			
Overhead	60%	of oper, maint & supv labor + maint mtl costs	136,975
Administration (2% total capital costs)	2%	of total capital costs (TCI)	467,105
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	233,553
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	233,553
Captial Recovery	9%	for a 20- year equipment life and a 7% interest rate	2,204,572
Total Indirect Operating Costs			**3,275,758**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**5,371,921**
Pollutant Removed (tons/yr)			**163.8**
Cost per ton of PM Removed			**32,799**

BART ANALYSIS 2004
WET ELECTROSTATIC PRECIPITATOR

Capital Recovery Factors		
Primary Installation		
Interest Rate	7.0%	
Equipment Life	20	years
CRF	0.0944	

Catalyst Replacement Cost		
Catalyst Life	2	years
CRF	0.5531	
Catalyst cost per unit	650	$/ft^3
Amount Required	0	ft^3
Catalyst Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	Assume Labor = 15% of catalyst cost (basis labor for baghouse replacement)
Total Installed Cost	**0**	
Annualized Cost	**0**	

Replacement Parts & Equipment		
Equipment Life	2	
CRF	0.5531	
Rep part cost per unit	33.72	$ each
Amount Required	0	Number
Total Rep Parts Cost	0	Cost adjusted for freight & sales tax
Installation Labor	0	10 min per bag (13 hr total) Labor at $29.65/hr
Total Installed Cost	**0**	
Annualized Cost	**0**	

Total Cost Replacement Parts & Catalyst **0**

Design Flow	115,000	dscfm	130682 scfm
	490	Temp Deg F	
	12%	% Moisture	
	231,188	acfm	

Operating Cost Calculations				**Annual hours of operation:**	**8,760**		
				Utilization Rate:	**90.0%**		
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Op Labor	25.38	Hr	1	hr/8 hr shift	986	25,013	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 90.0% of capacity
Supervisor	NA				NA	NA	Calc'd as % of labor costs
Maint Labor	0.12	$/ft^2 collector	70,264	ft^2 collector area		8,239	$/ft^2 collector area; $5775 if < 50,000 ft^2
Maint Mtls	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	381	kW-hr	3,003,623	140,930	$/kW-hr, 381.0 kW-hr, 8760 hr/yr, 90.0% of capacity
Natural Gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 90.0% of capacity
Water	0.22	Mgal	2081	gpm	984,249	219,832	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Comp Air	0.27	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 90.0% of capacity
Reagent #1(Caustic)	280	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
Reagent #2	300	Ton	0	lb-mole/hr	0	0	$/Ton, 0.0 lb-mole/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt% NaOH
SW Disposal	25	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
Haz W Disp	273	Ton	0.000	ton/hr	0	0	$/Ton, 0.468 lb/ton, 8760 hr/yr
WW Treat	1.52	Mgal	2081	gpm	984,249	1,498,856	$/Mgal, 2,080.7 gpm, 8760 hr/yr, 90.0% of capacity
Catalyst	650	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 90.0% of capacity
Rep Parts	33.72	$/bag	0	bags	2 yr life	0	$/$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 90.0% of capacity

*annual use rate is in same units of measurement as the unit cost factor

Emission Control Rate Calculation

Uncontrolled Emission Rate						
Emission Factor	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
0.47	lb/ton	700,000	tpy	NA	**163.80**	
Controlled Emission Rate						
Perf Guarantee	**Unit of Measure**	**Flow Rate**	**Unit of Measure**	**Control Eff. %**	**Emis Rate T/yr**	**Comments/Notes**
				99.99%	**0.0**	Currently assumes 99.99%.
Emission Reduction T/yr					**163.8**	

Electrical Consumption Requirements Kilowatts

					kW	
	Flow acfm	D P in H2O	Blower-Motor Eff			
Blower	231,188	5	0.65		208.1	OAQPS Cost Cont Manual 6th ed - Eq 3.46
	Flow gpm	D P ft H2O	Pump Eff	Motor Eff		
Pump 1	2081	60	0.8	0.9	32.6	OAQPS Cost Cont Manual 5th ed - Eq 9.49
Pump 2	0	60	0.8	0.9	0.0	OAQPS Cost Cont Manual 5th ed - Eq 9.49
	Area sqft	TR pwr	# Hoppers	Htr Pwr		
ESP	70,264	136.3	2	4	140.3	OAQPS Cost Cont 5th ed - Eq 6.29 & 6.30

Caustic Use	37.40	lb/hr SO2	2.50	lb NaOH/lb SO2	0.047	T/hr Caustic
Lime Use	37.40	lb/hr SO2	1.53	lb Lime/lb SO2	0.029	T/hr Lime

Estimate Area (ft2)		
Area #1	48503	ft2
Flow #1	159588	acfm
Flow #2	231,188	acfm
Area #2	**70264.0**	**ft2**

APPENDIX D. EPA CoST MODEL FROM PROPOSAL FOR STEEL SOURCE CATEGORY

To create the following table, Trinity extracted the following data from the CoST software program which was downloaded from the Community Modeling and Analysis System (CMAS) on May 23, 2022. https://www.cmascenter.org/cost/

The downloaded CoST software program contained data tables showing all available control measures applicable to various pollutants. Trinity first filtered the data tables filtered to only show ones applicable to NOx reduction. The remaining measures were filtered again to those with titles containing the word "Steel". CoST presented the control efficiencies and a summary of the applicable NOx reduction control measures as tables, which were exported to a .csv file. There was no data editing to the CoST export tables, only combining data tables from CoST into the single table here.

Additionally, Trinity obtained the CoST model used for the proposed rule via OneDrive link from Charlie Fulcher (EPA) as described in an email from Robin Langdon (EPA) dated 5/27/2022.
Trinity verified that the CoST model for the proposed rule used the same references as those from the Cost program downloaded on 5/23/2022.

cmname	cmabbreviation	majorpoll	controltechnology	sourcegroup	Control Efficiency (%)	Cost Year	Cost Per Ton	Reference Year Cost Per Ton	sector	class	equiplife	neidevice code	date reviewed	datasource	description
Low Excess Air; Iron & Steel Mills - Reheating	NLEAISRH	NOX	Low Excess Air	Iron & Steel Mills - Reheating	13	1990	1320	2109.54	ptnonipm	Known	10		2006	299|289|281|308	Application: The reduction in NOx emissions is achieved through the use of low excess air techniques, such that there is less available oxygen convert fuel nitrogen to NOx. This control applies to iron & steel reheating furnaces classified under SCC 30300933. Discussion: Low excess air works by reducing levels of excess air to the combustor, usually by adjustments to air registers and/or fuel injection positions, or through control of overfire air dampers. The lower oxygen concentration in the burner zone reduces conversion of the fuel nitrogen to NOx. Also, under excess air conditions in the flame zone, a greater portion of fuel-bound nitrogen is converted to N2 therefore reducing the formation of fuel NOx (ERG, 2000).
Low NOx Burner and Flue Gas Recirculation; Iron & Steel Mills - Galvanizing	NLNBFISGV	NOX	Low NOx Burner and Flue Gas Recirculation	Iron & Steel Mills - Galvanizing	60	1990	580	926.92	ptnonipm	Known	9		2006	289|308|283	Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel galvanizing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Iron & Steel - In-Process Combustion - Process Gas -Coke Oven/ Blast Furnace	NLNBFISIPCG	NOX	Low NOx Burner and Flue Gas Recirculation	Iron & Steel - In-Process Combustion - Process Gas -Coke Oven/ Blast Furnace	55	1990	3190	5098.06	ptnonipm	Known	15			289|283	Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to operations with in-process combustion (Process Gas - Coke Oven/ Blast Furnace) in the Iron & Steel industry with uncontrolled NOx emissions greater than 10 tons per year.
					55	1990	2470	3947.4							
Low NOx Burner and Flue Gas Recirculation; Iron and Steel Production - Annealing or Soaking Pits	NLNBFISPASP	NOX	Low NOx Burner and Flue Gas Recirculation	Iron and Steel Production - Annealing or Soaking Pits	60	1990	750	1198.6	ptnonipm	Known	10		2006	289|283	Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: Soaking pits are a combustion source which can fire natural gas, oil or coal. Emissions of NOx are similar to boilers emissions. LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner and Flue Gas Recirculation; Iron and Steel Production; Blast Heating or Reheating	NLNBFISPBR	NOX	Low NOx Burner and Flue Gas Recirculation	Iron and Steel Production; Blast Heating or Reheating	77	1990	380	607.29	ptnonipm	Known	5		2006	289|308|283	Application: This control is the use of low NOx burner (LNB) technology and flue gas recirculation (FGR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to reheating processes in iron production operations with blast heating stoves ant uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner; Iron & Steel - In-Process Combustion - Natural Gas or Coke Oven Process Gas	NLNBISIPCG	NOX	Low NOx Burner	Iron & Steel - In-Process Combustion - Natural Gas or Coke Oven Process Gas	50	1990	2200	3515.9	ptnonipm	Known	15	204|205		289|283	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to operations with in-process combustion (Natural Gas or Coke Oven Process Gas) in the Iron & Steel industry with uncontrolled NOx emissions greater than 10 tons per year.
					50	1990	1800	2876.65							
Low NOx Burner and Selective Non-catalytic Reduction; Iron & Steel Mills - Annealing	NLNBNISAN	NOX	Low NOx Burner and Selective Noncatalytic Reduction	Iron & Steel Mills - Annealing	80	1990	1720	2748.8	ptnonipm	Known	15		2017	289|308|283	Application: This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002). Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

Low NOx Burner and Selective Catalytic Reduction; Iron & Steel Mills - Annealing	NLNBSISAN	NOX	Low NOx Burner and Selective Catalytic Reduction	Iron & Steel Mills - Annealing	90	1990	4080	6520.4	ptnonipm	Known	15		2017	289|308|283	Application: This control is the use of low NOx burner (LNB) technology and selective catalytic reduction (SCR) to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to small (<1 ton NOx per OSD) iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNB's create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNB's create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002). Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).
Low NOx Burner; Iron & Steel Mills - Annealing	NLNBUISAN	NOX	Low NOx Burner	Iron & Steel Mills - Annealing	50	1990	570	910.94	ptnonipm	Known	10	204|205	2006	289|308|283	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel annealing operations with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner; Iron & Steel Mills - Galvanizing	NLNBUISGV	NOX	Low NOx Burner	Iron & Steel Mills - Galvanizing	50	1990	490	783.09	ptnonipm	Known	10	204|205	2017	289|308|283	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel galvanizing operations (SCC 30300936) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner; Iron & Steel Mills - Reheating	NLNBUISRH	NOX	Low NOx Burner	Iron & Steel Mills - Reheating	66	1990	300	479.44	ptnonipm	Known	10	204|205	2017	289|308|283	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to iron and steel reheating operations (SCC 30300933) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Low NOx Burner; Steel Foundries; Heat Treating Furn	NLNBUSFHT	NOX	Low NOx Burner	Steel Foundries; Heat Treating Furn	50	1990	570	910.94	ptnonipm	Known	10	204|205	2006	289|308|283	Application: This control is the use of low NOx burner (LNB) technology to reduce NOx emissions. LNBs reduce the amount of NOx created from reaction between fuel nitrogen and oxygen by lowering the temperature of one combustion zone and reducing the amount of oxygen available in another. This control is applicable to heat treating operations at steel foundries (SCC 30400704) with uncontrolled NOx emissions greater than 10 tons per year. Discussion: LNBs are designed to ""stage"" combustion so that two combustion zones are created, one fuel-rich combustion and one at a lower temperature. Staging techniques are usually used by LNB to supply excess air to cool the combustion process or to reduce available oxygen in the flame zone. Staged-air LNBs create a fuel-rich reducing primary combustion zone and a fuel-lean secondary combustion zone. Staged-fuel LNBs create a lean combustion zone that is relatively cool due to the presence of excess air, which acts as a heat sink to lower combustion temperatures (EPA, 2002).
Selective Catalytic Reduction; Iron & Steel Mills - Annealing	NSCRISAN	NOX	Selective Catalytic Reduction	Iron & Steel Mills - Annealing2	90	1999	5269	7020.39	ptnonipm	Known	20	139	2017	289|304|283|287|280|285	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. Applies to iron and steel annealing operations with NOx emissions greater than 10 tons per year. Discussion: Selective Catalytic Reduction (SCR) has been widely applied to stationary source, fossil fuel-fired, combustion units for emission control since the early 1970s. SCR is typically implemented on units requiring a higher level of NOx control than achievable by SNCR or other combustion controls (EPA, 2002). Like SNCR, SCR is based on the chemical reduction of the NOx molecule. The primary difference between SNCR and SCR is that SCR uses a metal-based catalyst to increase the rate of reaction (EPA, 2002). A nitrogen based reducing reagent, such as ammonia or urea, is injected into the flue gas. The reagent reacts selectively with the flue gas NOx within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NOx. The use of a catalyst results in two advantages of the SCR process over SNCR, the higher NOx reduction efficiency and the lower and broader temperature ranges. However, the decrease in reaction temperature and increase in efficiency is accompanied by a significant increase in capital and operating costs (EPA, 2002). The cost increase is due to the large amount of catalyst required. The SCR system can utilize either aqueous or anhydrous ammonia as the reagent. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Today, catalyst formulations include single component, multi-component, or active phase with a support structure. Most catalyst formulations contain additional compounds or sup-ports, providing thermal and structural stability or to increase surface area (EPA, 2002). The rate of reaction determines the amount of NOx removed from the flue gas. The important design and operational factors that affect the rate of reduction include: reaction temperature range; residence time available in the optimum temperature range; degree of mixing between the injected reagent and the combustion gases; uncontrolled NOx concentration level; molar ratio of injected reagent to uncontrolled NOx; ammonia slip; catalyst activity; catalyst selectivity; pressure drop across the catalyst; catalyst pitch; catalyst deactivation; and catalyst management (EPA, 2001).

Selective Catalytic Reduction; Iron & Steel - In-Process Combustion - Bituminous Coal	NSCRISIPCC	NOX	Selective Catalytic Reduction	Iron & Steel - In-Process Combustion - Bituminous Coal	90	1999	3027	4033.16	ptnonipm	Known	20	139		277|205	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process combustion (Bituminous Coal) in the Iron & Steel industry with uncontrolled NOx emissions greater than 10 tons per year.
Selective Catalytic Reduction; Iron & Steel - In-Process Combustion - Natural Gas and Process Gas - Coke Oven Gas	NSCRISIPCG	NOX	Selective Catalytic Reduction	Iron & Steel - In-Process Combustion - Natural Gas and Process Gas - Coke Oven Gas	90	1999	4953	6599.35	ptnonipm	Known	20	139	2017	277|205	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process combustion (Natural Gas and Process Gas - Coke Oven Gas) in the Iron & Steel industry.
Selective Catalytic Reduction; Iron & Steel - In-Process Combustion - Residual Oil	NSCRISIPCO	NOX	Selective Catalytic Reduction	Iron & Steel - In-Process Combustion - Residual Oil	90	1999	4458	5939.82	ptnonipm	Known	20	139	2017	277|205	Application: This control is the selective catalytic reduction of NOx through add-on controls. SCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). The SCR utilizes a catalyst to increase the NOx removal efficiency, which allows the process to occur at lower temperatures. This control is applicable to operations with in-process combustion (Residual Oil) in the Iron & Steel industry with uncontrolled NOx emissions greater than 10 tons per year.
Selective Non-Catalytic Reduction; Iron & Steel Mills - Annealing	NSNCRISAN	NOX	Selective Non-Catalytic Reduction	Iron & Steel Mills - Annealing	60	1990	1640	2620.95	ptnonipm	Known	15	107	2017	289|304|308|283	Application: This control is the reduction of NOx emission through selective non-catalytic reduction add-on controls. SNCR controls are post-combustion control technologies based on the chemical reduction of nitrogen oxides (NOx) into molecular nitrogen (N2) and water vapor (H2O). This control applies to iron and steel mill annealing operations with uncontrolled NOx emissions greater than 10 tons per year, classified under SCC 30300934. Discussion: SNCR is the reduction of NOx in flue gas to N2 and water vapor. This reduction is done with a nitrogen based reducing reagent, such as ammonia or urea. The reagent can react with a number of flue gas components. However, the NOx reduction reaction is favored for a specific temperature range and in the presence of oxygen (EPA, 2002). Both ammonia and urea are used as reagents. The cost of the reagent represents a large part of the annual costs of an SNCR system. Ammonia is generally less expensive than urea. However, the choice of reagent is also based on physical properties and operational considerations (EPA, 2002). Ammonia can be utilized in either aqueous or anhydrous form. Anhydrous ammonia is a gas at atmospheric pressure and normal temperatures. There are safety issues with the use of anhydrous ammonia, as it must be transported and stored under pressure (EPA, 2002). Aqueous ammonia is generally transported and stored at a concentration of 29.4% ammonia in water. Urea based systems have several advantages, including several safety aspects. Urea is a nontoxic, less volatile liquid that can be stored and handled more safely than ammonia. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing mixing (EPA, 2002). Because of these advantages, urea is more commonly used than ammonia in large boiler applications.

APPENDIX E. REPRESENTATIVE SCR COST EFFECTIVENESS CALCULATIONS

Summary of U.S. Steel representative unit SCR cost analyses

Unit Type	CSAPR NO_X Limit[1]		Exhaust Temperature °F	Exhaust Flowrate acfm	NO_X Emissions from Reheat tpy	CO_2 Emissions from Reheat tpy	Total Capital Investment 2021$	Total Annual Costs 2021$	NO_X Removed[2] tons/year	Cost Effectiveness 2021$
Annealing Furnace	0.06	lb/MMBtu	500	65,574	2	2,637	4,272,741	1,144,126	40	28,523
LMF	0.1	lb/ton	98	77,000	23	27,612	23,543,813	5,548,696	3	1,733,478
Coke Pushing	0.015	lb/ton coal	138	298,569	72	86,725	56,107,975	15,067,419	5	3,121,677
Ladle Preheater	0.06	lb/MMBtu	300	18,806	2	2,411	1,170,408	664,409	11	62,036

1. CSAPR Proposed Rule Table I.B-4 Summary of Proposed NOX Emissions Limits for Iron and Steel and Ferroalloy Emissions Units
2. Assumes a NO_X removal efficiency of 70%.

In order to determine the economic feasibility to retrofit Selective Catalytic Reduction (SCR) technology on existing NOx-emitting sources, Trinity utilized the EPA Air Pollution Control Cost Manual (CCM), Section 4, Chapter 2, Selective Catalytic Reduction, NOx Controls, EPA/452/B-02-001 (https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf). The approach incorporates methodologies from the 6/12/2019 version of the CCM for SCR design parameters and annual costs while utilizing the approach from the 1/2002 CCM for direct and indirect costs. The 2002 manual reflects a more robust determination for direct and indirect costs for SCR as equations incorporate several sensitivity cases, while the 2019 approach is based on the Clean Air Markets Division (CAMD) Integrated Planning Model (IPM) for utility and industrial boilers. The CCM presents cost estimation for industrial boilers via modified IPM equations to replace electricity production ratings with "typical" boiler heat input capacities using boiler net plant heat rate (NPHR). Neither version of the CCM presents cost estimation methodology specific to non-boiler

Critical inputs to the CCM model include heat input rate represented by the total maximum burner heat input to the unit, observed actual exhaust gas temperature and flow rate, actual annual NOx emissions and operating hours for the unit (potential-to-emit has not been utilized for the cost model for a retrofit system), and several market cost data for ammonia, natural gas, and electricity. To employ the CCM methodology for units which do not combust fuel via a burner, such as electric arc furnaces and ladle metallurgy furnaces, the heat input has been calculated utilizing the 40 CFR 75 Table 1 natural gas F-factor and the known exhaust gas flow associated with unit to determine a simulated heat input. Also, SCR operate at optimum control efficiency at approximately 700F, therefore, the approach incorporates reheating the exhaust gas stream via a natural gas-fired duct burner to elevate the current exhaust gas temperature to the target temperature. The combined gas volume from the existing system and natural gas reheat process is utilized for SCR design parameters such as the catalyst area. NOx emissions generated by the reheat process have been quantified via an AP-42 Chapter 1.4 natural gas combustion NOx emission factor, but are not incorporated into the cost effectiveness determination. Further, the cost model includes direct and operating cost associated with a NOx analyzer as determined by EPA's Emission Measurement Center (EMC): Continuous Emission Monitoring Systems

Key output parameters of the cost model include Total Capital Investment (TCI) and cost effectiveness, calculated as the total NOx removed from the exhaust gas at 70% SCR control efficiency divided by the annualized SCR system cost.

SCR Cost Analysis

Detailed SCR Cost Analysis ***(note this is a sample calculation for one process unit - the same steps were used for all U.S. Steel process units to calculate $/ton)***

Parameter	Variable	Calculation	Cost	Units	Reference
Unit Type	Annealing Furnace				
Unit Operating Parameters					
Heat Input Rate	Q_B		121.1	MMBtu/hr	Maximum Heat Input Rate
Exhaust Gas Temperature	T		500	deg F	Average of exhaust gas temperature from *baseline period* at stack outlet (Stack test, DAS data, or conservative estimate)
Exhaust Gas Flow	$q_{fluegas(NoReheat)}$	scfm*(14.7 psi/14.7 psi)*(T+460)/ (68°F+460)	65,574	acfm	Maximum exhaust flowrate from *baseline period* (Stack test, DAS data, or conservative estimate); Assumed dry exhaust gas; Conversion from scfm to acfm based on temperature only (68°F standard temperature; 460 = conversion from °F to Rankine); No significant pressure change assumed (14.7 psi = standard pressure)
Exhaust Gas Flow With Natural Gas Reheat	$q_{fluegas}$	[$q_{fluegas(NoReheat)}$ + $NG_{required}$ / F-factor$_{Natural\ Gas}$ (wscf/Mcf) /t_{SCR}]* (T_{SCR}+460)/ (T+460)	66,789	acfm	Flow volume into SCR catalyst following required reheat of flue gas stream to target SCR operating temperature; Natural Gas wet F-factor (10,610 wscf/MMBtu) per EPA Method 19 (8/3/17); Natural Gas HHV (1,020 MMBtu/10^6 scf) per AP-42 Chapter 1.4 (July 1998); Natural Gas F-factor = 10,610 scf/MMBtu*1,020 MMBtu/10^6 scf* 10^3 Mcf/cf = 10,822 wscf flue gas/Mcf natural gas; Conversion from acfm at process exhaust temperature to acfm at SCR operating temperature based on temperature only (460 = conversion from °F to Rankine) and no significant pressure change assumed (14.7 psi = standard pressure)
Actual Annual NOx Emission Rate	NOx_{annual}		57	tpy	Maximum annual NOx emissions from *baseline period*
Annual Unit Operating Hours	AOH		7,884	hr/yr	Annual operating hours associated with maximum annual NOx emissions from *baseline period*
SCR Control Efficiency	*e*	Maximum efficiency	70	%	EPA/452/F-03-032 SCR Control Technology Fact Sheet
SCR Operating Hours	t_{SCR}	Maximum operation	7,884	hr/yr	Assuming 100% uptime; Operated 100% of time during unit operation
SCR Operating Temperature	T_{SCR}		700	deg F	Optimum SCR operation at 700°F per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.2.2
Inlet Concentration	NOx_{in}	(NOx_{annual}*2,000 lb/ton) / (Q_B*AOH)	0.12	lb/MMBtu	Calculation at maximum heat input rate.
Outlet Concentration	NOx_{out}	NOx_{in}*(1-*e*)	0.04	lb/MMBtu	Based on SCR control efficiency; Assumes operation at maximum heat input rate.
Available Cost Data					
Capital Cost of Ammonia Catalyst	$CC_{initial}$	(\$8,000/m^3)/(35.3147 ft^3/m^3)	248	\$/ft^3	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, footnote 4; Adjusted from 2010 dollar.
Cost of 19% Ammonia	$C_{NH3solution}$	\$/gal/Den_{NH3}	0.5631	\$/lb	Based on \$0.5631/gallon from Tanner Industries, Inc. budgetary pricing (10/1/2020)
Industrial Natural Gas Price	$Cost_{NG}$		5.5	\$/Mscf	EIA Natural Gas Prices for 2021 - U.S. Total Industrial Price
Industrial Electricity Rate	$Cost_{elect}$		0.1059	\$/kWh	EIA Electricity Data for 2020 - U.S. Total
Chemical Properties and Constants					
Ammonia Solution Density	Den_{NH3}		7.51	lbs/gal	Density of 19% Ammonia Solution
Ammonia Molecular Weight (MW)	$M_{reagent}$		17.03	g/mol	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR
NO_2 MW	M_{NOx}		46.01	g/mol	
Ratio of Equivalent Moles of NH_3 per Mole of Reagent Injected	$SR_{theoretical}$		1	mol NH_3 : mol reagent	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR
Ratio of Equivalent Moles of NH_3 per mole of NOx	SRF		1.05	mol NH_3:mol NOx	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.3.7
Constant 1	c_1		7	ft	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.3.12
Constant 2	c_2		9	ft	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.3.12
SCR Design Data					
Empty Catalyst Layers	n_{empty}		0	layers	Conservatively assumed for lowest capital cost
Nominal Height of Each Catalyst Layer	h'_{layer}		3.1	ft	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.3.12
Number SCR Chambers	n_{scr}		1	chamber	Conservatively assumed for lowest capital cost
Allowable Slip	Slip		2	ppm	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.2.2. Minimum range of allowable slip.
Pressure Drop due to Duct	ΔP_{duct}		3	in	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.5
Pressure Drop due to Catalyst	$\Delta P_{catalyst}$		1	in	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.5

Detailed SCR Cost Analysis ***(note this is a sample calculation for one process unit - the same steps were used for all U.S. Steel process units to calculate $/ton)***

Parameter	Variable	Calculation	Cost	Units	Reference
Operating Life of Catalyst in Hours	$h_{catalyst}$		20,000	hours	Per 2019 EPA Cost Manual, Sec 4, Chp 2, Part 2.4.2; Assumed average of high-dust SCR as a catalyst layer is typically guaranteed for 16,000 - 24,000 operating hours.
NOx Removal Efficiency	η_{NOx}	$(NOx_{in}-NOx_{out})/NOx_{in}*100\%$	70	%	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.10. Assumes constant removal efficiency without variation of catalyst activity, which decreases over time (2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.3.10).
Cross Sectional Area of Catalyst	$A_{catalyst}$	$q_{fluegas}$/(16ft/sec x 60 sec/min)	70	ft^2	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.28.
Cross Sectional area of SCR reactor	A_{SCR}	$A_{catalyst}$*1.15 (15% greater than $A_{catalyst}$)	80	ft^2	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.29.
Temp Adjustment	T_{adj}	$15.16-(0.03937*T)+(0.0000274*(T^2))$	2.33	deg F	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.27
Slip Adjustment	$Slip_{adj}$	(1.2835-(0.0567*Slip))	1.17		Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.24
Inlet NOx Adjustment	NOx_{adj}	$(0.8524+(0.3208*NOX_{in}))$	0.89		Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.25
NOx Efficiency Adjustment	η_{adj}	$(0.2869+(1.058*\eta_{NOx}))$	1.03		Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.23
Volume of Catalyst	$Vol_{catalyst}$	$2.81*Q_B*\eta_{adj}*NOX_{adj}*Slip_{adj}*T_{adj}/n_{scr}$	848	ft^3	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.22
Height of catalyst layer	h_{layer}	$Vol_{catalyst}/(N_{layer}*A_{catalyst})+1$	4	ft	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.32
Number of catalyst layers	n_{layer}	$Vol_{catalyst}/(h'_{layer}*A_{catalyst})$	4	layers	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.31
Total Number of catalyst layers	n_{total}	$n_{layer} + n_{empty}$	4	layers	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.33
Height of SCR	h_{scr}	$n_{total}*(C1+h_{layer})+C2$	53	ft	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.34
Mass flow of reagent	$m_{reagent}$	$(NOx_{in}*Q_B*\eta_{NOx}*SRF*M_{reagent})/(M_{NOx})$	4	lb/hr	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.35
Mass flow of solution	m_{sol}	$m_{reagent}/C_{sol}$	21	lb/hr	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.36
Direct Costs					
Catalyst Cost	$f(Vol_{catalyst})$	$Vol_{catalyst}*CC_{initial}$	210,271	$	Calculated
Ammonia Flow Adjustment	$f(NH_3rate)$	$\$411/(lb/hr)*m_{reagent}/Q_B-\$47.3/MMBtu/hr$	-62	$/(MMBtu/hr)	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.38; Adjusted from 1998 dollar
SCR height Adjustment	$f(h_{scr})$	$\$6.12/(ft-MMBtu/hr)*h_{scr}-\$187.9/MMBtu/hr$	250	$/(MMBtu/hr)	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.37; Adjusted from 1998 dollar
Retrofit "Boiler" Adjustment	f(new)	$0/MMBtu/hr	0	$/(MMBtu/hr)	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.40
Bypass Adjustment	f(bypass)	$127/MMBtu/hr	0	$/(MMBtu/hr)	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.42; No Bypass Installed
Ammonia Slip Monitoring	NH_3MON_{cost}	70,000	94,961	$	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Section 2.2.2; Adjusted from 2009 dollar
NOx, O_2, and Flow Monitoring	$NOxMON_{cost}$		221,191	$	NOx analyzer, O_2 analyzer, flow monitor; Cost per EMC: Continuous Emission Monitoring Systems CEMS Cost Model Version 3.0 (3/7/2007); Adjusted from 2007 dollar
Total Direct Cost	DC	$Q_B[3,380/MMBtu/hr+f(h_{scr})+f(NH_3rate)+f(new)+f(bypass)](3,500/Q_B)^{0.35}+f(Vol)+NH_3MON_{cost}+NOxMON_{cost}$	3,016,015	$	Adapted from 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.36; Adjusted from 1998 dollar
Indirect Costs					
Performance Test	PT_{cost}	Budgetary Cost	20,000	$	Testing of Catalyst Core (Engineering Estimate)
General Facilities	GF_{cost}	0.05*DC	150,801	$	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Table 2.5
Engineering and Home Office Fees	EO_{cost}	0.10*DC	301,602	$	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Table 2.5
Process Contingency	PC_{cost}	0.05*DC	150,801	$	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Table 2.5
Total Indirect Installation Costs	B	$PT_{cost}+GF_{cost}+EO_{cost}+PC_{cost}$	623,203	$	Calculated
Project Contingency	C	0.15*(DC+B)	545,883	$	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.4.1

SCR Cost Analysis

Detailed SCR Cost Analysis ***(note this is a sample calculation for one process unit - the same steps were used for all U.S. Steel process units to calculate $/ton)***

Parameter	Variable	Calculation	Cost	Units	Reference
Total Capital Investment					
Total Plant Costs	D	DC+B+C	4,185,101	$	-
Preproduction Costs	G	0.02*D	83,702	$	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Table 2.5
Inventory Capital	H	$C_{NH3solution}$*m_{sol}*14 days*24 hr/day	3,938	$	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Table 2.5; Based on 14 days of SCR operation, 24 hrs/day
Total Capital Investment	**TCI**	**D+G+H**	**4,272,741**	**$**	**Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Table 2.5**
Total Annual Costs					
			Direct Annual Costs		
Operator Labor Costs	OL_{cost}	t_{SCR}/24 hr/day* 4 hr/day* $60/hr	103,044	$	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Parts 2.4.2 & 2.5; Adjusted from 2016 dollar
Supervisor Labor Costs	SL_{cost}	0.15*OL_{cost}	15,457	$	Assumed minimal - 15% of Operating Labor Rate per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 1.5.1
Annual Maintenance Costs	AM_{cost}	0.005*TCI	21,364	$	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.57
Annual Reagent Costs	AR_{cost}	$C_{NH3solution}$*m_{sol}*t_{SCR}	92,405	$	Adapted from 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.58
Annual Electricity Costs	AE_{cost}	P*$Cost_{elect}$*t_{SCR} = (0.1*Q_B)*1,000*0.0056*(CoalF *HRF)$^{0.43}$* $Cost_{elect}$*t_{SCR}	56,639	$	Adapted from 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equations 2.61 & 2.62; CoalF assumed 1 per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.4.1.3; HRF assumed 1 per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.3.2 (NPHR=10)
Annual Continuous Monitoring System Cost	$AnnualMON_{cost}$		93,926	$	Cost per EMC: Continuous Emission Monitoring Systems CEMS Cost Model Version 3.0 (3/7/2007); Adjusted from 2007 dollar; Includes a 15% contingency factor to account for annual Ammonia Slip monitor QAQC which has not been estimated via the EMC Cost Model
Catalyst Replacement Costs	CR_{cost}	n_{SCR}*Vol_{cat}*($CC_{initial}$/n_{layer})	52,568	$	Adapted from 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.63; Conservatively assumes replacing 1 layer at a time vs full replacement (n_{layer}=R_{layer})
Future Worth Factor	FWF	i*[1/(1+i)$^{hcatalyst/tSCR}$-1)	0.4		Adapted from 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equations 2.65 and 2.66
Annual Catalyst Replacement Cost	ACR_{cost}	CR_{cost}*FWF	20,711	$	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.64.
Annual Natural Gas Cost for Reheat	NG_{cost}	$NG_{required}$*$Cost_{NG}$	241,709		
Density of Air at Exhaust Temp	ρ_{air}	*n/V=P/(R*T)*	*0.0014*	*lb-mole/scf*	*Calculated using Ideal Gas Law at standard condition of 14.7 psi and Exhaust Gas Temperature (T) where Ideal Gas Constant (R) = 10.731577089016 psi·ft^3 ·/ lb-mole·°R*
Specific Heat of Air at Exhaust Temp	C_p	*Btu/lb-°F * 29 lb/lb-mole*	*7.67*	*Btu/lb-mole °F*	*Calculated using Specific Heat of Air at Exhaust Gas Temperature (T) (Btu/lb-°F) x Molecular Weight of Air (29 lb/lb-mole)*
Reheat Burner Heat Input Requirement	*Reheat*	*(68°F+460)/(T+460)*ρ_{air} *C_p *(T_{SCR}-T)*120%*	*1.45*	*Btu/acf*	*Required natural gas input to increase flue gas temperature for optimum SCR operation; Includes 20% contingency factor to account for burner inefficiency*
Natural Gas Required for Reheat	$NG_{required}$	$q_{fluegas(NoReheat)}$ *Reheat/$HHV_{Natural Gas}$ * 60 min/hr*t_{SCR}	*43,947*	*Mcf/year*	*Natural Gas HHV (1,020 MMBtu/10^6 scf) per AP-42 Chapter 1.4 (July 1998)*
Direct Annual Costs	DA_{cost}	OL_{cost}+SL_{cost}+AM_{cost}+AR_{cost}+ AE_{cost}+$AnnualMON_{cost}$+ ACR_{cost}+NG_{cost}	**645,254**	**$/year**	Adapted from 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.56.
			Indirect Annual Costs		
Administrative Charges	A_{cost}	0.03*OL_{cost}+0.4*AM_{cost}	11,637	$/year	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.69.
Overhead Costs	O_{cost}	0.6*(OL_{cost}+SL_{cost}+AM_{cost})	83,918	$/year	Per 2002 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 1.5.2.
Indirect Annual Costs	IAcost	A_{cost}+O_{cost}	**95,555**	**$**	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.68
			Annualized Capital Costs		
Interest Rate	i		7.00%		Per 2018 EPA Cost Manual, Sec 1, Chp 2 Cost Estimation: Concepts and Methodology, Part 2.5.2
SCR System Life	Life		20	years	Assumes 20 year life of equipment per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Part 2.4.2.
Capital Recovery Factor	CRF	i(1+i)^{life}/((1+i)^{life}-1)	9.44%		Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.71
Annualized Capital Cost	AC_{cost}	CRF*TCI	**403,317**	**$/year**	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.70
Total Annual Costs	**TAC**	**ACcost+DAcost+IAcost**	**1,144,126**	**$/year**	**Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.72.**

SCR Cost Analysis

Detailed SCR Cost Analysis ***(note this is a sample calculation for one process unit - the same steps were used for all U.S. Steel process units to calculate $/ton)***

Parameter	Variable	Calculation	Cost	Units	Reference
Cost Effectiveness					
NOx Generated From NG Reheat	NOx_{Reheat}	$NG_{required}$ / 10^3 Mcf/MMcf* 100 lb NOx/MMscf/ 2,000 lb/ton	2.20	ton/yr	NOx emission factor per AP-42 Chapter 1.4 Natural Gas Combustion, Table 1.4-1 for Small Boilers Uncontrolled (100 lb NOx/10^6 scf)
NOx Removed Per Year	$NOx_{removed}$	$NOx_{in}*\eta_{NOx}*Q_B*AOH/2{,}000$ lb/ton	40.11	ton/yr	Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.11; **Does not include NOx generated due to reheating of the flue gas to optimum SCR operating temperature.**
Cost Effectiveness (2021$)		**$TAC/NOx_{removed}$**	**28,523**	**$/ton**	**Per 2019 EPA Cost Manual, Sec 4, Chp 2 SCR, Equation 2.73**

Chemical Engineering Plant Cost Index:

Year	Index
1995	381.1
1996	381.7
1997	386.5
1998	389.5
1999	391.8
2000	394.1
2001	394.3
2002	395.6
2003	402
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9
2010	550.8
2011	593.2
2012	584.6
2013	567.3
2014	576.1
2015	556.8
2016	541.7
2017	567.5
2018	603.1
2019	607.5
2020	596.2
2021	708

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN

ADDRESSING REGIONAL OZONE TRANSPORT FOR

THE 2015 8-HOUR NAAQS.

June 21, 2022

EXHIBIT E:

United States Steel SIP Disapproval Comments

United States Steel Corporation
600 Grant Street
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E- mail: dwhacker@uss.com

David W. Hacker
Senior Counsel

April 25, 2022

Submitted via email – davidson.olivia@epa.gov
and uploaded to https://www.regulations.gov **(Docket ID No. EPA–R05–OAR–2022–0006)**

Olivia Davidson
Attainment Planning and Maintenance Section
Air Programs Branch
U.S. Environmental Protection Agency Region V
77 West Jackson Boulevard
Chicago, IL 60604

Dear Olivia Davidson:

Re: ***Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region V Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, Proposed Rule, Docket ID No. EPA–R05–OAR–2022–0006***

United States Steel Corporation ("U. S. Steel") is submitting these comments pertaining to the above-referenced proposed rule. U. S. Steel has worked diligently with the Illinois Environmental Protection Agency (IEPA), Indiana Department of Environmental Management (IDEM), Michigan Environment, Great Lakes and Energy (EGLE), Minnesota Pollution Control Agency (MPCA), and Ohio Environmental Protection Agency (OEPA) on reducing emissions of nitrogen oxides from our facilities in these states and is committed to doing our fair share by employing practical, technologically feasible and cost-effective means to ensure the areas in which we operate attain and maintain the ozone National Ambient Air Quality Standard (NAAQS); and ensuring that emissions from our sources do not interfere with downwind states' ability to attain and/or maintain the ozone NAAQS. The above-referenced state agencies submitted State Implementation Plans (SIPs) that meet the "interstate transport" provision of Clean Air Act section 110(a)(2)(D)(i)(I), and therefore the SIPs should be approved.

U. S. Steel respectfully notes that in its proposed disapproval, U.S. EPA made some critical errors and, therefore, we believe that in the spirit of cooperative federalism, that U.S. EPA reconsider the State submittals and approve the SIP submittals; or if U.S. EPA still finds deficiencies with the SIPs, that the states be given the opportunity to correct any asserted deficiencies before U.S. EPA proceeds with promulgating a final rule disapproving the SIPs and issuing a Federal Implementation Plan (FIP). It is significant to note that Congress contemplated States be given an opportunity to correct deficiencies with SIPs (before U. S. EPA proceeds with a FIP) when enacting the Clean Air Act. The actions in disapproving the SIP and proceeding with issuing a FIP (even before the SIP is disapproved) runs afoul of the process afforded to States and federal cooperative federalism.

U. S. Steel has several comments regarding the proposed disapproval of the above-referenced SIPs, including:

- The Proposed Disapproval is Not Based upon Accurate Projected Emission Estimates; and the Model Over-Predicts Impacts
- The One Percent Contribution Criterion is Not Appropriate as it is Lower than What U.S. EPA Advised States and it is Lower Than What Can be Supported Based on the Precision of the Modeling
- Even if the SIPs Did Not Satisfy EPA Approval Criteria, States Should be Given the Opportunity to Supplement the SIP Submittal or Otherwise Correct the Asserted Deficiencies Before U.S. EPA finalizes Disapproval of the SIP and Proceeds with a Federal Implementation Plan
- By Simultaneously Proceeding with a FIP, EPA's Proposed Actions Supplant States' Rights and Authority Under the Clean Air Act as Congress Contemplated
- Judicial Review of Any Disapproved SIP Belongs in the Appropriate Circuit Court for the State

The Proposed Disapproval Is Not Based Upon Accurate Projected Emission Estimates and the Model Over-Predicts Impacts

The emission estimates from sources that would be affected by the rule are incorrect; and do not reflect the actual projected emissions. These emission estimates do not include reductions that have been and will be implemented under other actions.

For example, it does not appear that U.S. EPA has considered current and projected emission reductions that have resulted from years of effort by both U.S. EPA and the taconite industry in revising the Federal Implementation Plan (FIP) for regional haze in Minnesota. In addition, undoing or redoing the evaluations and productive efforts that have occurred for over 10 years that have resulted in significant NOx reductions that have been shown to be technologically and economically feasible is inefficient and inappropriate. In sum, these efforts, and most importantly, these reductions must be considered in U. S. EPA's evaluation.

While U. S. Steel disagrees with EPA's proposed threshold of 1 percent, if the data are corrected and incorporated into modeling for Minnesota, it would show that Minnesota's contribution impact is less than EPA's 1 percent proposed "interference" threshold as previously demonstrated by LADCO and U. S. EPA. Second, to the extent that U. S. EPA somehow still finds that emissions from these sources "contribute" or "interfere" with down wind states' ability to attain and maintain the ozone NAAQS, which does not seem plausible, U. S. EPA will need to re-evaluate its costs determinations in the separate ozone transport FIP rulemaking.

The emission estimates from other sources, including those in Illinois, Indiana, Ohio and Michigan – and in particular, emissions from the iron and steel sources in those states, are overstated and are inconsistent with prior state submittals. Finally, separate from the emission estimates, the modeling used in the disapproval over-predicts impacts from the upwind states and sources.

The One Percent Contribution Criterion is Not Appropriate as it is Lower Than EPA Advised States and it is Lower Than What Can be Supported Based on the Precision of the Modeling

U. S. Steel notes that while U.S. EPA may believe the modeling used to support its disapproval of the SIPs is accurate and precise, the accuracy and precision of the modeling does not support an impact threshold of 0.70 ppb. U.S. EPA needs to consider the accuracy and the precision of the modeling when determining an appropriate "interference" threshold. U. S. Steel acknowledges that a model cannot necessarily be "perfect" as U. S. EPA points out, but the U.S. EPA's decisions and impacts to the regulated need to reflect the model's accuracy and precision. U. S. Steel further notes that affected states and the regulated community reasonably relied on 1 ppb threshold that U.S. EPA found to be appropriate; and it is inappropriate for U. S. EPA now to unilaterally disapprove any SIP because in its SIP submittal, the state used a 1 ppb threshold.

Even if the SIPs Did Not Satisfy EPA Approval Criteria, States Should be Given the Opportunity to Supplement the SIP Submittal or Otherwise Correct the Asserted Deficiencies Before U.S. EPA finalizes Disapproval of the SIP and Proceeds with a Federal Implementation Plan

U. S. Steel notes that U.S. EPA's action in disapproving SIPs that were submitted to U.S. EPA years ago and now years later is proposing to disapprove the SIPs and not giving the State an opportunity to supplement the SIP submittal or otherwise correct the asserted deficiencies is inconsistent with Congress' intent for the Federal government and States to work collaboratively on ensuring the NAAQS are maintained.

By simultaneously proceeding with a FIP, EPA's actions supplant states' rights and authority under the clean air act as Congress contemplated

U. S. EPA Cannot Replace Sound State Decisions that Comply with the Clean Air Act with Federal "Judgment" or "Policy". It is well established that States have much latitude in developing and implementing State Implementation Plans (SIPs.) While U.S. EPA may prefer a different approach or alternative, a SIP can only be disapproved when is irrefutably shown to be inconsistent with the Clean Air Act. In the proposed disapproval, U.S. EPA has not shown that the state submittals did not comply with the Clean Air Act. The proposed disapproval of the SIPs is tied closely to EPA's proposed FIP that would have a "one-size fits all" approach that would inappropriately supplant the States' individual authority under the Clean Air Act. Procedurally, U.S. EPA should have afforded the States the opportunity to correct any asserted deficiencies before U.S. EPA proceeded with a FIP. The states were not given such an opportunity.

Judicial Review of Any Disapproved SIP Belongs in the Appropriate Circuit Court for the State

The disapproval of the individual SIPs does not have nationwide effect regardless how U.S. EPA attempts to characterize its proposed action. If finalized as proposed, the rule would result in the disapproval of SIPs for Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin. Each SIP has individual, unique sources, and unique air quality aspects. The SIP submittals are unique to each State. Each state has different types of sources. The issues are unique to each State. The impacts of disapproving these State SIPs are local and regional to the affected states and industries in those states. While U.S. EPA may prefer to have a “one size fits all” approach in developing a FIP to replace these SIPs; this does not change the fact that Congress gave States primary responsibility to adopt State Implementation Plans. The individual State submittals are unique to the individual State and sources; and disapproval of any SIP is presumably unique to the individual State.

For the reasons stated herein, U. S. Steel requests that U.S. EPA approve the SIPs for Illinois, Indiana, Michigan, Minnesota and Ohio; or, in the alternative, provide each State adequate time to review and respond to any deficiencies. We appreciate the U.S. EPA’s careful consideration of these comments.

Sincerely,

David W. Hacker

United States Steel Corporation Law Department
600 Grant Street, Ste. 1800
Pittsburgh, PA 15219
Phone: 479-200-9743 Fax: 412-433-2964
kjones@uss.com
Kendra Jones
Assistant General Counsel - Environmental

April 25, 2022

ATTN: Docket ID No. EPA-RO6-OAR-2021-0801

Administrator Michael Regan
C/O EPA Docket Center (EPA/DC)
Docket ID No. EPA-RO6-OAR-2021-0801
U.S. Environmental Protection Agency
Fuerst.sherry@epa.gov

Submitted via Federal eRulemaking Portal

RE: Comments to EPA's *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards*, 87 Fed. Reg. 9798 (February 22, 2022)

Dear Administrator Regan,

United States Steel Corporation ("U. S. Steel") appreciates the opportunity to submit the following comments on behalf of our corporation and all subsidiaries to the United States Environmental Protection Agency ("EPA"). U. S. Steel Corporation started in 1901 and has evolved and grown with America over the years. Our most recent growth can be seen in Arkansas with our mini-mill construction announcement in February of this year. As a corporation operating in Arkansas, U. S. Steel is a party impacted by this rule and as such, U. S. Steel provides comments on EPA's *Air Plan Disapproval; Arkansas, Louisiana, Oklahoma, and Texas; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards* (Proposal). U. S. Steel also supports the Arkansas Environmental Federation ("AEF") comments submitted regarding the Proposal and incorporates those comments by reference.

The Arkansas Department of Energy and Environment, Division of Environmental Quality ("DEQ") is best situated to review, evaluate and address the impacts of the NAAQS on Arkansas businesses and industries and developed the SIP complying with the NAAQS requirements. DEQ developed an appropriate and approvable SIP for the State of Arkansas and thus incorporates by reference the comments submitted on April 22, 2022, by the DEQ ("DEQ Comments") in Docket ID No. EPA-RO6-OAR-2021-0801. U. S. Steel requests that EPA reevaluate the Arkansas SIP based upon all information submitted, including DEQ Comments, and approve the Arkansas SIP.

DEQ has expended an enormous amount of time and worked diligently to meet the NAAQS for ozone. DEQ worked to develop the information necessary to formulate the SIP, developed a proposed plan, and undertook the required state-rulemaking and legislative action. DEQ also worked collaboratively with EPA Region 6. Numerous discussions were held by DEQ and EPA Region 6 to inform DEQ's development of an appropriate SIP. DEQ responded to questions and comments from EPA Region 6 to develop the SIP. Additionally, DEQ developed additional information in response to EPA Region 6's comments as a part of a collaborative process that EPA has now abandoned.

EPA has a role in the SIP process. However, that role should be a narrow one that gives deference to the state pursuant to the cooperative federalism system established under the Clean Air Act ("CAA"). EPA's proposal to disapprove Arkansas's interstate transport SIP for the 2015 ozone NAAQS[1] goes beyond the authority given to EPA by the CAA. State's, such as Arkansas, are given discretion under the CAA to address NAAQS through appropriate plans.[2] EPA's proposal oversteps the agency authority under the CAA. The Arkansas SIP should be re-evaluated by EPA solely on the basis of whether Arkansas has met the applicable CAA requirements. EPA should not use the SIP disapproval process to try to create a "national ozone transport policy".

EPA's Proposal to disapprove Arkansas's SIP while also promulgating a FIP is not the proper timing of rulemaking on this issue. EPA not allowing DEQ to submit revisions to the SIP, this action impairs the state's ability to make state specific analyses regarding over-reach on controls by EPA. DEQ should be permitted time to analyze, address and/or correct any deficiencies identified by EPA before finalizing a FIP. Although EPA might generally have the authority under Section 7410(c)(1)(B) to issue a FIP at any time prior to the 2-year deadline after disapproval (EME Homer S.Ct., 134 S.Ct. 1584 (2014)), nevertheless, CAA Section 7410(c)(1) contemplates that a state would be provided time to correct any deficiency and that EPA has the discretion to allow up to two years for correction of any deficiency. EPA's determination about whether a FIP should be promulgated immediately as to a specific state should be based on a state-specific analysis since a State may bring a particularized, as-applied challenge to a nationwide or regional transport rule (EME Homer on remand, 795 F.3d 118 (D.C. Cir. 2015). EPA should not move to finalize the proposed FIP with respect to Arkansas until DEQ has been provided adequate time to review and respond.

[1] *See* 42 U.S.C. § 7410(a) (requiring States to submit plans to implement, maintain, and enforce NAAQS); *see also Com. of Va. v. EPA*, 108 F.3d 1397, 1407 (D.C. Cir.), decision modified on reh'g, 116 F.3d 499 (D.C. Cir. 1997) (stating that the CAA "expressly gave the states initial responsibility for determining the manner in which air quality standards were to be achieved.").

[2] *See Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976) ("Each State is given wide discretion in formulating its plan."); *Train v. NRDC*, 412 U.S. 60, 79 (1975) ("[EPA] is relegated by the [Clean Air] Act to a secondary role in the process of determining and enforcing the specific, source-by-source emission limitations which are necessary if the national standards it has set are to be met."); *Fla. Power & Light Co. v. Costle*, 650 F.2d 579, 587 (5th Cir. 1981) ("The great flexibility accorded the states under the Clean Air Act is further illustrated by the sharply contrasting, narrow role to be played by EPA.").

EPA claims that the appropriate venue for challenges to EPA's final action on the interstate transport SIPs for Louisiana, Arkansas, Texas, and Oklahoma is the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit").[3] Unser Section 307(b)(1) of the CAA, to determine venue for challenges to EPA actions, the relevant questions are whether the action is: (1) a nationally applicable action; (2) a locally or regionally applicable action; or (3) a locally or regionally applicable action based on a determination that has nationwide scope or effect.[4]

EPA attempts to claim that the SIP, if finalized, would be "nationally applicable" because it would address four states and "would apply uniform, nationwide analytical methods, policy, judgments and interpretation with respect to the same CAA obligations." [5] EPA's statements and stated reasoning are not adequate to make this a "nationally applicable" decision and would not be consistent with other SIP decisions. Specifically, this approach is inconsistent with EPA's SIP decisions regarding Florida, Georgia, North Carolina, and South Carolina [6] which involved four states and two Federal judicial circuits and relied on the same EPA analysis. EPA did not determine it was "nationally applicable" and determined that judicial review must be filed in the United States Court of Appeal for the appropriate circuit. [7]

EPA attempts to claim that the SIP rulemaking for ozone transport for Arkansas, Louisiana, Texas and Oklahoma will be nationally applicable and have a nationwide scope. However, EPA's proposed action is one that will be locally or regionally applicable with all the states in the same region and only impacts the four states. Petitions for review of EPA's final action regarding the interstate ozone transport SIPs may be brought only in the court of appeals for the appropriate circuit. Any Petition for Review of EPA's final action with respect to Arkansas's SIP, should be brought the U.S. Court of Appeals for the Eighth Circuit.

For the reasons set forth above and those provided in the comments filed by DEQ and AEF, U. S. Steel requests EPA approve the Arkansas SIP, or in the alternative, provide DEQ adequate time to review and respond to any deficiencies identified by EPA through a SIP Call.

U. S. Steel appreciates the opportunity to provide comments on the Proposal to disapprove the SIP. If you have any questions or should you need additional information, please do not hesitate to contact me at 479-200-9743 or kjones@uss.com.

Sincerely,

KAJ

Kendra A. Jones, Esq.
Assistant General Counsel - Environmental
United States Steel Corporation

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[3] 87 Fed. Reg. at 9835.
[4] *See* 42 U.S.C. § 7807(b)(1); *see also Texas v. EPA*, 829 F.3d 405, 418 (5th Cir. 2016).
[5] 87 Fed. Reg. at 9835.
[6] Air Plan Approval; FL, GA, NC, SC; Interstate Transport (Prongs 1 and 2) for the 2015 8-Hour Ozone Standard, 86 Fed. Reg. 68,413 (Dec. 2, 2022).
[7] 86 Fed. Reg. at 68,430.

UNITED STATES STEEL CORPORTATION

COMMENTS ON

PROPOSED FEDERAL IMPLEMENTATION PLAN

ADDRESSING REGIONAL OZONE TRANSPORT FOR

THE 2015 8-HOUR NAAQS.

June 21, 2022

EXHIBIT F:

United States Steel FIP Extension of Time to Comment Request

United States Steel Corporation Law Department
600 Grant Street, Ste. 1800
Pittsburgh, PA 15219 Phone: 479-200-9743 Fax: 412-433-2964
kjones@uss.com
Kendra Jones
Assistant General Counsel - Environmental

May 26, 2022

ATTN: Docket ID No. EPA-HQ-OAR-2021-0668

Administrator Michael Regan
C/O EPA Docket Center (EPA/DC)
Docket ID No. EPA-HQ-OAR-2021-0668
U.S. Environmental Protection Agency

Submitted via Federal eRulemaking Portal (Regulations.gov)

RE: Request for Extension of Comment Period, "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard" Docket No. EPA-HQ-OAR-2021-0668. *Federal Register* 87 Fed. Reg. 20,036 (April 6, 2022).

Dear Administrator Regan,

United States Steel Corporation ("U. S. Steel") respectfully requests at least an additional 60-day extension for the comment period on the proposed "Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard" Docket No. EPA-HQ-OAR-2021-0668. *Federal Register* 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed FIP"). U. S. Steel appreciates the slight extension of the comment period, but more time is needed. The original comment deadline of June 6, 2022 was extended briefly by EPA however the new EPA comment deadline of June 21, 2022 still does not provide adequate time for the complexity and breadth of the proposed rule. Commenters should have until at least August 8, 2022, to provide meaningful and substantive technical and legal comments on this Proposed FIP.

The Proposed FIP is unparalleled in terms of geography, scope, industry, and impacted emissions units, the breadth of impact and all the supporting information requires an in-depth review of EPA's work. A thorough and proper review would include at minimum working through the photochemical modeling analyses and its underlying data inputs. The data needed to even conduct such a review was not provided by EPA at the time of publication of the Proposed FIP and must be requested from EPA. Many requests for the data have been made by various interested parties and the role out of information is taking days and even weeks – which further reduces the time available for any meaningful review during the comment period. Even if the data is provided timely there is not sufficient time to review and do independent analyses and modeling – for multiple state and dozens of facilities - prior to the June 21, 2022, comment deadline.

To allow appropriate time for interested parties to provide meaningful review and comment on such a complex rule requires extensive time and manpower. The proposed FIP is 180 pages the online docket contains 191 groups of records including dozens of documents and spreadsheets. This review and work necessary is even more challenging for corporations who have multiple states and emission impacts to review. Not to mention the simultaneous running of comment periods for the various SIP Disapproval dockets, like for instance Docket No. EPA-R06-OAR-2021-0801which U.S. Steel also commented on during this time.

Throughout the Proposed FIP it seems as if EPA intends to provide critical data only upon request. The data is essential to fully evaluate all of EPA's assessments related to Non-EGU emissions, control costs, and air quality impacts. The EPA Screening Assessment of Potential Emissions Reductions, Air Quality Impacts and Costs from Non-EGU Emissions Units for 2026 (Non-EGU Screening Assessment) refers and cites extensively to model inputs, codes and Control Strategy Tool ("CoST") run data that no one has unless they specifically request the data from EPA. The Proposed FIP relies heavily on this information, and it should be available for review and scrutiny by any interested stakeholder.

Since the data required to consider this vast rule is not already provided U. S. Steel requests the following be provided:

1. The air quality contribution data that EPA used to identify potentially impactful industries in 2023 and the R code that processed these data; [1]
2. The CoST run results and the R code that generated the curves EPA used for identifying a cost threshold to evaluate emissions reductions in potentially impactful industries in 2023; [2]
3. The maximum emission reduction CoST run results that EPA used to assess Non-EGU emission reduction potential and estimated air quality impact in potentially impactful industries in 2023;[3]
4. The 2023 state-receptor specific Revised CSAPR Update ("RCU") ppb/ton values, the RCU calibration factors used in the air quality assessment tool ("AQAT") for control analyses in 2023, the R code that processed the CoST run results using the maximum emission reduction algorithm, and the summaries of the air quality improvements; [4]
5. The 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in the AQAT for ozone for control analyses in 2023, and the R code that processed the CoST run results that EPA used for its impactful boiler assessment;[5]

[1] Non-EGU Screening Assessment at 3, FN9.
[2] *Id* at 4, FN12.
[3] *Id* at 5, FN14.
[4] *Id* at 5, FN16.
[5] *Id* at 6, FN20.

6. The R code that processed the CoST run results, the sector-specific (non-EGU specific) ppb/ton values, and the 2026 AQAT calibration factors used to prepare the Non-EGU Screening Assessment tables on estimated emissions reductions, maximum PPB improvement, and costs. [6]

The expectation of EPA is that stakeholders to review volumes data, wait for data requests to be fulfilled, evaluate 53 distinct elements of the Proposed FIP and then look at "all aspects of the proposal." Expecting stakeholders to complete all of this within the currently allotted 75-days is not feasible or realistic. Simply, a proper level of review, analyses and response cannot be accomplished in this limited timeframe.

The timeframe for comments as currently proposed by EPA does not allow for or promote public engagement in the rule making process. Stakeholders must be afforded more time to develop and submit data and analyses that should be essential considerations for the EPA promulgation of well-supported and lawful rule. This is especially true in this instance, as a preliminary review of some of the data that time has afforded so far reveals critical errors in EPA's analyses which warrants a more thorough review of all aspects of the rule to ensure EPA's decision-making process is based upon sound science and reasoning.

U. S. Steel requests EPA provided an additional extension of the comment period for the Proposed FIP by at least an additional 60 days. Any shorter comment period simply does not provide stakeholders a meaningful opportunity to review, evaluate and comment.

U. S. Steel appreciates the consideration of this request. If you have any questions or wish to discuss, please do not hesitate to contact me at 479-200-9743 or kjones@uss.com.

Sincerely,

Kendra A. Jones, Esq.
Assistant General Counsel - Environmental
United States Steel Corporation

[6] *Id* at 6, FN20.

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit E

Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026 (Feb. 28, 2022)

TECHNICAL MEMORANDUM

TO: Docket for Rulemaking, "Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standards" (EPA-HQ-OAR-2021-0668)
DATE: February 28, 2022
SUBJECT: Screening Assessment of Potential Emissions Reductions, Air Quality Impacts, and Costs from Non-EGU Emissions Units for 2026

Note: EPA originally posted this document on March 11, 2022. This document, posted on March 29, 2022, corrects inadvertent errors referencing a filename on page 9 and in Table 5 on page 16.

I. Introduction

The EPA developed an analytical framework to facilitate decisions about industries, emissions unit types, and cost thresholds for including emissions units in the non-electric generating unit "sector" (non-EGUs) in a federal implementation plan (FIP) proposal for the 2015 ozone national ambient air quality standards (NAAQS) transport obligations. Using this analytical framework, we prepared a screening assessment for the year 2026.

This memorandum presents the analytical framework and summarizes the screening assessment the EPA prepared to identify industries and emissions unit types to include in proposed rules to obtain NOx emissions reductions from non-EGUs. Sections VII.A.2. and VII.C. of the proposal preamble include discussions of the non-EGU NOx emissions limits, compliance timing, and other related-rule requirements for the industries and emissions unit types identified through the screening assessment.

The remainder of this memorandum includes the following sections:

- II. Background on Analytical Framework
- III. The Analytical Framework
  - Step 1 -- Identifying Potentially Impactful Industries in 2023
  - Step 2a -- Identifying a Cost Threshold to Evaluate Emissions Reductions in Potentially Impactful Industries for 2023
  - Step 2b -- Assessing Non-EGU Emission Reduction Potential and Estimated Air Quality Impacts in Potentially Impactful Industries in 2023
  - Step 2c – Refining Tier 2 by Identifying Potentially Impactful Boilers in 2023
- IV. Modifying the Analytical Framework for the Screening Assessment for 2026
- V. Screening Assessment Results for 2026 -- Estimated Total Emissions Reductions, Air Quality Improvements, and Annual Total Costs for Emissions Units in Tier 1 Industries and Impactful Boilers in Tier 2 Industries
- VI. Request for Comment and Additional Information

II. Background on Analytical Framework

The number of different industries and emissions unit categories and types, as well as the total number of emissions units that comprise the non-EGU "sector"[1] makes it challenging to define a single method to identify impactful emissions reductions. We incorporated air quality information as a first step in the analytical framework to help determine potentially impactful industries to focus on for further assessing emission reduction potential, air quality improvements, and costs. Given the lengthy decision-making and analysis schedules for the FIP

[1] The non-EGU "sector" includes non-electric generating emissions units in various manufacturing industries and does not include municipal waste combustors (MWC), cogeneration units, or <25 MW EGUs. For a discussion of MWCs, cogeneration units, and EGUs <25 MW, see Section VI.B.3. of the proposed rule preamble.

proposal, we developed the analytical framework using inputs from the air quality modeling for the Revised CSAPR Update (RCU) for 2023[2], as well as the projected 2023 annual emissions inventory from the 2016v2 emissions platform that was used for the air quality modeling for the proposed rule.

Using the RCU modeling for 2023, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, which is 0.7 ppb (1% of a 70 ppb NAAQS). In 2023 there were 27 linked states for the 2015 NAAQS: AL, AR, CA, DE, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NV, OH, OK, PA, TN, TX, UT, VA, WI, WV, and WY.

To analyze non-EGU emissions units, we aggregated the underlying projected 2023 emissions inventory data into industries defined by 4-digit NAICS.[3] Then for the linked states, we followed the 2-step process below:

1. **Step 1** -- We identified industries whose potentially controllable emissions are estimated, by applying the analytical framework, to have the greatest ppb impact on downwind air quality, [4] and
2. **Step 2** – We determined which of the most impactful industries and emissions units had the most emissions reductions that would make meaningful air quality improvements at the downwind receptors at a marginal cost threshold we determined using underlying control device efficiency and cost information.

Additional details on these steps are presented in the Section III below.

Finally, the EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD,[5] that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season.[6] As such, we modified the analytical framework slightly and applied it for a screening assessment estimating potential emissions reductions, air quality improvements, and costs for the year 2026.

III. The Analytical Framework

Step 1 - Identifying Potentially Impactful Industries in 2023

The analytical framework starts with identifying industries whose potentially controllable emissions may contribute to downwind receptors. To identify industries that have large, meaningful air quality impacts from potentially controllable emissions, we estimated air quality contribution by 4-digit NAICS-based industry for 2023. To estimate the contributions by 4-digit NAICS at each downwind receptor, we used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the air quality assessment tool (AQAT) for control analyses in 2023.[7]

[2] We used the RCU air quality modeling for this screening assessment because the air quality modeling for the proposed rule was not completed in time to support this assessment.
[3] North American Industry Classification System (https://www.census.gov/naics/).
[4] To identify industries, we reviewed emissions units with >= 100tpy emissions units in the 2023 inventory in those industries in the upwind states.
[5] Final Technical Support Document (TSD) for the Final Cross-State Air Pollution Rule for the 2008 Ozone NAAQS, Assessment of Non-EGU NO_X Emissions Controls, Cost of Controls, and Time for Compliance Final TSD ("CSAPR Update Non-EGU TSD"), August 2016, available at *https://www.epa.gov/csapr/assessment-non-egu-NOx-emission-controls-cost-controls-and-time-compliance-final-tsd*.
[6] Note that information on control installation timing as detailed in the 2016 CSAPR Update Non-EGU TSD is not complete or sufficient to serve as a foundation for timing estimates for this proposed FIP.
[7] The calibration factors are receptor-specific factors. For the RCU, the calibration factors were generated using 2016 base case and 2023 base case air quality model runs. These receptor-level ppb/ton factors are discussed in the Ozone Transport

We focused on assessing emissions units that emit >100 tpy of NOx.[8] By limiting the focus to potentially controllable emissions, well-controlled sources that still emit > 100 tpy are excluded from consideration. Instead, the focus is on uncontrolled sources or sources that could be better controlled at a reasonable cost. As a result, reductions from any industry identified by this process are more likely to be achievable and to lead to air quality improvements.

Based on the industry contribution data, we prepared a summary of the estimated total, maximum, and average contributions from each industry and the number of receptors with contributions >= 0.01 ppb from each industry. We evaluated this information to identify breakpoints in the data, as described in detail in Appendix A. These breakpoints were then used to identify the most impactful industries to focus on for the next steps in the analysis.[9]

A review of the contribution data indicated that we should focus the assessment of NOx reduction potential and cost primarily on four industries. These industries each (1) have a maximum contribution to any one receptor of >0.10 ppb and (2) contribute >= 0.01 ppb to at least 10 receptors. We refer to these four industries identified below as comprising **"Tier 1"**.

- Pipeline Transportation of Natural Gas
- Cement and Concrete Product Manufacturing
- Iron and Steel Mills and Ferroalloy Manufacturing
- Glass and Glass Product Manufacturing

In addition, the contribution data suggests that we should include five additional industries as a second tier in the assessment. These industries each either have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors. We refer to these five industries identified below as comprising **"Tier 2"**.

- Basic Chemical Manufacturing
- Petroleum and Coal Products Manufacturing
- Metal Ore Mining
- Lime and Gypsum Product Manufacturing
- Pulp, Paper, and Paperboard Mills

Policy Analysis Final Rule TSD found here: https://www.epa.gov/sites/default/files/2021-03/documents/ozone_transport_policy_analysis_final_rule_tsd_0.pdf.

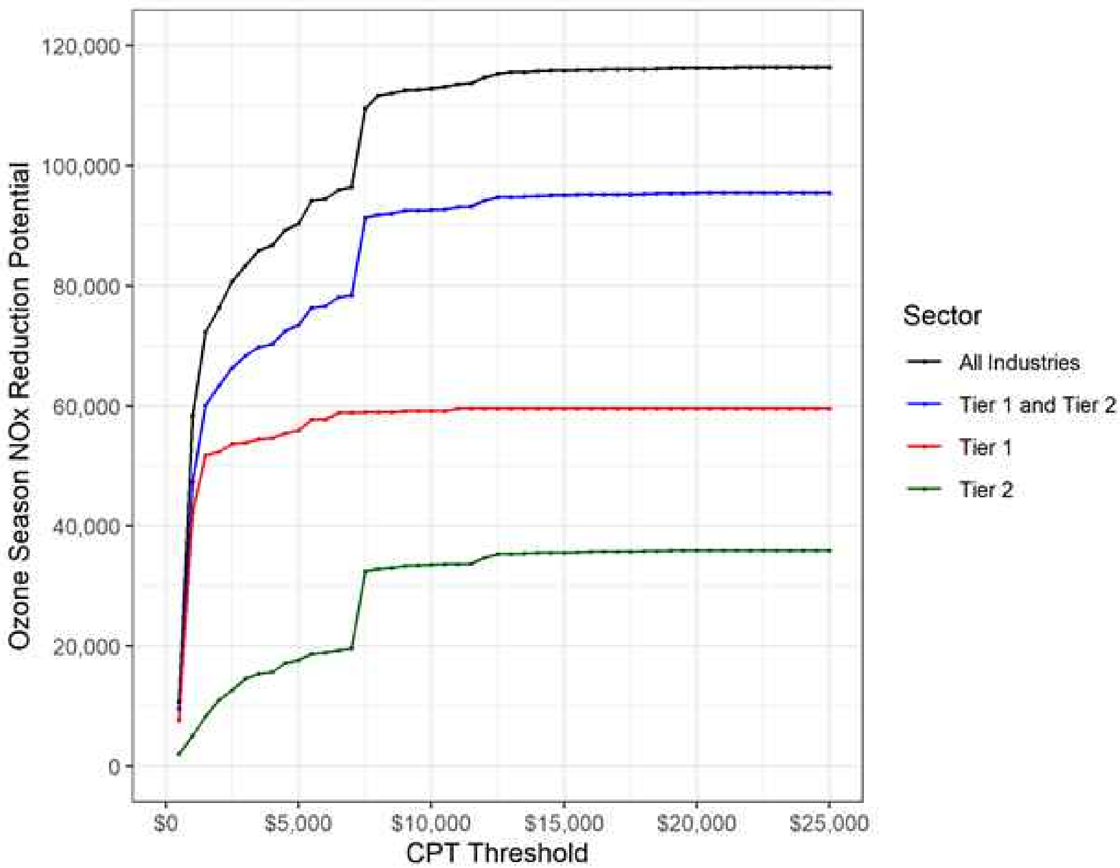
[8] In the non-EGU emission reduction assessment prepared for the Revised Cross State Air Pollution Rule Update (https://www.regulations.gov/document/EPA-HQ-OAR-2020-0272-0014), we reviewed emissions units with >150 tpy of NOx emissions. In this screening assessment, we broadened the scope to include emissions units with >=100 tpy of NOx emissions. We believe that emissions units that are smaller may already be controlled and reductions from these smaller units are likely to be more costly.

[9] The air quality contribution data and the R code that processed these data are available upon request.

Step 2a - Identifying a Cost Threshold to Evaluate Emissions Reductions in Potentially Impactful Industries for 2023

To identify an annual cost threshold for evaluating potential emissions reductions in the Tier 1 and Tier 2 industries, the EPA used the Control Strategy Tool (CoST)[10], the Control Measures Database (CMDB)[11], and the projected 2023 emissions inventory to prepare a listing of potential control measures, and costs, applied to non-EGU emissions units in the projected 2023 emissions inventory. Using this data, we plotted curves for Tier 1 industries, Tier 2 industries, Tier 1 and 2 industries, and all industries at $500 per ton increments. Figure 1 indicates there is a "knee in the curve" at approximately $7,500 per ton.[12] We used this marginal cost threshold to further assess estimated emissions reductions, air quality improvements, and costs from the potentially impactful industries. Note that controls and related emissions reductions are available at several estimated cost levels up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

Figure 1. Ozone Season NOx Reductions and Costs per Ton (CPT) for Tier 1, Tier 2 Industries, and Other Industries



[10] Further information on CoST can be found at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

[11] The CMDB is available at the following link: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-analysis-modelstools-air-pollution.

[12] The CoST run results, the CMDB, and the R code that generated the curves are available upon request.

Step 2b - Assessing Non-EGU Emission Reduction Potential and Estimated Air Quality Impacts in Potentially Impactful Industries in 2023

Next, using the marginal cost threshold of $7,500 per ton, to estimate emissions reductions and costs the EPA processed the CoST run using the maximum emission reduction algorithm[13,14] with known controls.[15] We identified controls for non-EGU emissions units in the Tier 1 and Tier 2 industries that cost up to $7,500 per ton. Note that $7,500 per ton represents a marginal cost, and controls and related emissions reductions are available at several estimated costs up to the $7,500 per ton threshold. The costs do not include monitoring, recordkeeping, reporting, or testing costs.

We then calculated air quality impacts associated with the estimated reductions for the 27 linked states in 2023 following the steps below.

1. We binned the estimated reductions by 4-digit NAICS code into the Tier 1 and Tier 2 industries.
2. We used the 2023 state-receptor specific RCU ppb/ton values and the RCU calibration factors used in the AQAT for control analyses in 2023. We multiplied the estimated non-EGU reductions by the ppb/ton values and by the receptor-specific calibration factor to estimate the ppb impacts from these emissions reductions.[16]

Note that we did not include the impact of reductions in the "home state" even if the "home state" was linked to receptor(s) in another state. That is, we only looked at the impact of NOx emissions reductions from upwind states. Furthermore, for each receptor we included impacts from states that are upwind to any receptor, not just those states that are upwind to that particular receptor.

Step 2c – Refining Tier 2 by Identifying Potentially Impactful Boilers in 2023

In 2023 because boilers represent the majority emissions unit in the Tier 2 industries for which there were controls that cost up to $7,500 per ton (see Table 1 below), we targeted emissions reductions and air quality improvements in Tier 2 industries by identifying potentially impactful industrial, commercial, and institutional (ICI) boilers.

[13] The maximum emission reduction algorithm assigns to each source the single measure (if a measure is available for the source) that provides the maximum reduction to the target pollutant. For more information, see the CoST User's Guide available at the following link: https://www.cmascenter.org/cost/documentation/3.7/CoST%20User's%20Guide/.
[14] The maximum emission reduction CoST run results and CMDB are available upon request.
[15] *Known controls* are well-demonstrated control devices and methods that are currently used in practice in many industries. *Known controls* do not include cutting edge or emerging pollution control technologies.
[16] The 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in AQAT for control analyses in 2023, the R code that processed the CoST run results using the maximum emission reduction algorithm, and the summaries of the air quality improvements are available upon request.

Table 1. Number of Emissions Unit Types in Tier 2 Industries

	Number of Emissions Units by Type		
Tier 2 Industries	**Boiler**	**Internal Combustion Engine**	**Industrial Processes**
Metal Ore Mining	--	1	15
Pulp, Paper, and Paperboard Mills	49	1	--
Petroleum and Coal Products Manufacturing	37	4	48
Basic Chemical Manufacturing	46	8	13
Lime and Gypsum Product Manufacturing	--	--	1
Totals	**132**	**14**	**77**

To identify potentially impactful boilers, using the projected 2023 emissions inventory in the linked upwind states we identified a universe of boilers with >100 tpy NOx emissions that had any contributions at downwind receptors.[17,18] We refined the universe of boilers to a subset of impactful boilers by sequentially applying the three criteria below to each boiler. This approach is similar to the overall analytical framework and was tailored for application to individual boilers.[19,20]

- Criterion 1 -- Estimated maximum air quality contribution at an individual receptor of >=0.0025 ppb ***or*** estimated total contribution across downwind receptors of >=0.01 ppb***.***
- Criterion 2 -- Controls that cost up to $7,500 per ton.
- Criterion 3 -- Estimated maximum air quality improvement at an individual receptor of >=0.001 ppb.

IV. Modifying the Analytical Framework for the Screening Assessment for 2026

EPA concluded, based on the most recent information available from the CSAPR Update Non-EGU TSD, that controls on all of the non-EGU emissions units cannot be installed by the 2023 ozone season. As such, we prepared a screening assessment for the year 2026 by generally applying the analytical framework detailed above. Specifically, we

- Retained the impactful industries identified in Tier 1 and Tier 2, the $7,500 cost per ton threshold, and the methodology for identifying impactful boilers,
- Modified the framework to address challenges associated with using the projected 2023 emissions inventory by using the 2019 emissions inventory, and
- Updated the air quality modeling data by using data for 2026.

Using the projected 2023 emissions inventory introduced challenges associated with the application of new source performance standards (NSPS).[21] Some of the projected emissions inventory records reflected percent

[17] We used the 2023fj non-EGU point source inventory files from the 2016v2 emissions platform.
[18] MD, MO, NV, and WY did not have boilers with >100 tpy NOx emissions.
[19] For the impactful boiler assessment, the estimated air quality contributions and improvements were not based on modeling of individual emissions units or emissions source sectors. The air quality estimates were derived by using the 2023 state/receptor specific RCU ppb/ton values and the RCU calibration factors used in AQAT. The results are intended to provide a general indication of the relative impact across sources.
[20] For the impactful boiler assessment, the 2023 state-receptor specific RCU ppb/ton values, the RCU calibration factors used in the AQAT for ozone for control analyses in 2023, and the R code that processed the CoST run results are available upon request.
[21] Using the projected inventory also introduced challenges associated with the growth of emissions at sources over time. EPA determined that the 2019 inventory was appropriate because it provided a more accurate prediction of potential near-

reductions associated with the application of current NSPS (e.g., Reciprocating Internal Combustion Engine, Natural Gas Turbines, Process Heaters NSPS). Applying NSPSs during the emissions projections process includes estimating the number of modifications/replacements that would trigger NSPS requirements. None of the existing sources, as they currently exist, would install a control because of a NSPS. But some of those sources might modify and become subject to the NSPS. Because we do not know which sources might become subject to an NSPS by modifying, across-the-board percent reductions from unknown control measures are applied to all of the sources.[22] As a result, CoST replaced some of the unknown control measures with a control measure that it concluded was more efficient. However, we do not know if a control would be applied to a particular source in response to the NSPS rules and if so, what that control would be. Therefore, we do not know if CoST is correctly replacing those unknown control measures. To address this challenge, we used a current, not projected, emissions inventory along with the latest air quality modeling information for 2026. Specifically, we used the 2019 inventory for information on emissions, emissions units, and estimated emissions reductions in concert with the emissions sector-specific (non-EGU-specific) ppb/ton factors for 2026 and 2026 AQAT calibration factors to estimate the impacts on future air quality from reductions at emissions units as those units currently exist.[23]

V. Screening Assessment Results for 2026 -- Estimated Total Emissions Reductions, Air Quality Improvements, and Annual Total Costs for Emissions Units in Tier 1 Industries and Impactful Boilers in Tier 2 Industries

This screening assessment is not intended to be, nor take the place of, a unit-specific detailed engineering analysis that fully evaluates the feasibility of retrofits for the emissions units, potential controls, and related costs. We used CoST to identify emissions units, emissions reductions, and costs to include in a proposed FIP; however, CoST was designed to be used for illustrative control strategy analyses (e.g., NAAQS regulatory impact analyses) and not for unit-specific, detailed engineering analyses. The estimates from CoST identify proxies for (1) non-EGU emissions units that have emission reduction potential, (2) potential controls for and emissions reductions from these emissions units, and (3) control costs from the potential controls on these emissions units.

See Sections VII.A.2. and VII.C. of the proposal preamble for discussions of the NOx emissions limits, compliance timing, and other related rule requirements for the industries and emissions unit types identified through this screening assessment.

To prepare the screening assessment for 2026, we applied the analytical framework detailed in the sections above with the modifications discussed in the previous section. The assessment includes emissions units from the Tier 1 industries and impactful boilers from the Tier 2 industries. Using the latest air quality modeling for 2026, we identified upwind states linked to downwind nonattainment or maintenance receptors using the 1% of the NAAQS threshold criterion, or 0.7 ppb. In 2026 there are 23 linked states for the 2015 NAAQS: AR, CA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NV, OH, OK, PA, TX, UT, VA, WI, WV, and WY.
We re-ran CoST with known controls, the CMDB, and the 2019 emissions inventory. We specified CoST to allow replacing an existing control if a replacement control is estimated to be >10 percent more effective than the

term emissions reductions. For additional discussion of the 2019 inventory, please see the *2019 National Emissions Inventory Technical Support Document: Point Data Category* available in the docket. In switching to the 2019 inventory, however, we did not account for any growth or decrease in emissions that might occur at individual units. Because the controls applied by CoST have efficiencies, or percent reductions, this means we could be over- or under-estimating the emission reductions and their ppb impacts.

[22] For additional information on the 2016v2 inventory and the projected 2023 emissions inventory, please see the September 2021 *Technical Support Document Preparation of Emissions Inventories for 2016v2 North American Emissions Modeling Platform* in the docket or available at the following link: https://www.epa.gov/system/files/documents/2021-09/2016v2_emismod_tsd_september2021.pdf.

[23] For this proposed FIP, the EPA used the ozone AQAT, which is described in detail in *Ozone Policy Analysis Proposed Rule TSD* in the docket. The receptor-state specific calibration factors for 2026 were derived using the following air quality modeling runs: 2026 base case and 2026 control case with 30 percent across-the-board NOx emissions cuts.

existing control. We did not replace an existing control if the 2019 emissions inventory indicated the presence of that control, even if the CMDB reflects a greater control efficiency for that control. Also, we removed six facilities from consideration because they are subject to an existing consent decree, are shut down, or will shut down by 2026. See Appendix B for a summary of the facilities removed.

For the emissions units in the Tier 1 industries and the impactful boilers in the Tier 2 industries, the estimated emissions reductions, air quality improvements, and costs are summarized below and in Tables 2 through 5 that follow. The cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.[24] As shown in Table 2, the total estimated ozone season emissions reductions are 47,186 tons, the estimated total ppb improvement across all downwind receptors is 5.16 ppb, and the estimated total cost is $410.8 million annually. The estimated ozone season reductions, total ppb improvements, and total cost are representative of single year impacts and not cumulative impacts.

Table 3 presents estimated ppb improvements at receptors grouped by region. For the coastal Connecticut/New York City nonattainment area receptors, total ppb improvements from Tier 1 and Tier 2 range from 0.247 to 0.356 ppb; for the receptors near Chicago, total ppb improvements range from 0.261 to 0.375 ppb; for the receptors along the western shoreline of Lake Michigan in Wisconsin, total ppb improvements range from 0.360 to 0.443 ppb; for the Houston receptors, total ppb improvements range from 0.284 to 0.472 ppb; and for the western receptors, ppb improvements range from <0.001 to 0.056 ppb. There are far fewer emissions reductions from western states because there are far fewer states and impacted emissions units in the west, and the resulting air quality improvements are noticeably lower.

For Tier 1 industries and the impactful boilers in the Tier 2 industries, Table 4 provides by state and by industry estimated emissions reductions and costs; Table 4a provides by state, estimated emissions reductions and costs. New Jersey and Nevada are not included in these tables because they did not have any estimated non-EGU reductions from the Tier 1 industries and boilers in Tier 2 industries that cost up to $7,500 per ton. In addition, Figure 2 shows the geographical distribution of ozone season reductions.

Table 5 provides by industry and east/west, the number and type of emissions units, total estimated emissions reductions, total ppb improvements, and costs. There are 489 emissions units contributing to the total estimated reductions of 47,186 ozone season tons and total estimated ppb improvements of 5.16 ppb.[25]

Table 6 includes by industry, the emissions source group, control technology, number of emissions units, ozone season emissions reductions, and annual total cost for the emissions units in the screening assessment. Lastly, Tables 7, 8, and 9 provide summaries of estimated ozone season emissions reductions, annual total cost, and average cost per ton by the control technologies CoST applied (i) across all non-EGU emissions units, (ii) across non-EGU emissions units grouped by the Tier 1 industries and impactful boilers in Tier 2 industries, and (iii) across non-EGU emissions units grouped by the seven individual Tier 1 and 2 industries.

[24] EPA submitted an information collection request (ICR) to OMB associated with the proposed monitoring, calibrating, recordkeeping, reporting and testing activities required for non-EGU emissions units -- *ICR for the Proposed Rule, Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard: Transport Obligations for non-Electric Generating Units*, EPA ICR No. 2705.01. The ICR is summarized in Section XI.B.2 of the proposed rule preamble. The ICR includes estimated monitoring, recordkeeping, reporting, and testing costs of approximately $11.45 million per year for the first three years. These costs are not reflected in the cost estimates presented in Tables 2 through 9.

[25] While the number of units listed in Table 5 sums to 491, the emissions inventory records for two of the units in Tier 1 industries include SCCs for both boilers and industrial processes. As a result, those units appear twice in the counts.

For the Excel workbooks with Tables 2 through 9, see *Transport Proposal – NonEGU Results – 03-16-2022.xlsx* and *Non-EGU Analysis Controls – 11-15-2021.xlsx* in the docket.[26]

[26] The R code that processed the CoST run results, the sector-specific (non-EGU-specific) ppb/ton values, and the 2026 AQAT calibration factors used to prepare these tables are available upon request.

All costs are in 2016$ and do not include monitoring, recordkeeping, reporting, or testing costs.

Table 2. Estimated Emissions Reductions (ozone season tons), Maximum PPB Improvements, and Costs

Option	Ozone Season Emissions Reductions (East/West)	Total PPB Improvement Across All Downwind Receptors	Max PPB Improvement Across All Downwind Receptors	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Industries (# of emissions units > 100 tpy in identified industries)
Tier 1 Industries with Known Controls that Cost up to $7,500/ton	41,153 (37,972/3,181)	4.352	0.392	$356.6 ($3,610)	Cement and Concrete Product Manufacturing (47), Glass and Glass Product Manufacturing (44), Iron and Steel Mills and Ferroalloy Manufacturing (39), Pipeline Transportation of Natural Gas (307)
Tier 2 Industry Boilers with Known Controls that Cost up to $7,500/ton	6,033 (5,965/68)	0.809	0.169	$54.2 ($3,744)	Basic Chemical Manufacturing (17), Petroleum and Coal Products Manufacturing (10), Pulp, Paper, and Paperboard Mills (25)

The estimated ozone season reductions, total ppb improvements, and total cost are representative of single year impacts and not cumulative impacts.

Table 3. Estimated PPB Improvements at Receptors Grouped by Region*

Receptor ID	State	Receptor Name	Average/Max PPB Improvement Needed to Attain	Home State PPB Contribution	Tier 1	Tier 2	Total
90010017	CT	Greenwich	0.6/1.3	9.3	0.231	0.016	0.247
90013007	CT	Stratford	1.9/2.8	4.1	0.332	0.024	0.356
90019003	CT	Westport	3.7/3.9	2.9	0.314	0.022	0.336
90099002	CT	Madison	-/1.5	3.9	0.323	0.023	0.346
170310001	IL	Chicago/Alsip	-/1.6	19.4	0.196	0.065	0.261
170310032	IL	Chicago/South	-/0.8	16.6	0.299	0.076	0.375
170310076	IL	Chicago/ComEd	-/0.4	18.7	0.229	0.060	0.289
170314201	IL	Chicago/Northbrook	-/1.5	21.4	0.262	0.069	0.332
170317002	IL	Chicago/Evanston	-/1.1	18.9	0.307	0.049	0.356
550590019	WI	Kenosha/Water Tower	0.8/1.7	5.8	0.325	0.035	0.360
550590025	WI	Kenosha/Chiwaukee	-/0.2	2.6	0.392	0.051	0.443
551010020	WI	Racine/Racine	-/1.2	10.8	0.353	0.044	0.397
480391004	TX	Houston/Brazoria	-/0.3	29.3	0.302	0.169	0.472
482010024	TX	Houston/Aldine	3.3/4.8	29.7	0.186	0.098	0.284
40278011	AZ	Yuma	-/0.9	2.8	0.027	0.001	0.028
60070007	CA	Butte	-/-0.8	23.5	0.000	0.000	0.000
60170010	CA	El Dorado #1	4.1/6.5	26.7	0.000	0.000	0.000
60170020	CA	El Dorado #2	2.3/4.1	28.7	0.000	0.000	0.000
60190007	CA	Fresno #1	8.6/10.4	29.1	0.001	0.000	0.001
60190011	CA	Fresno #2	11/11.9	31.1	0.002	0.000	0.002
60195001	CA	Fresno #3	11.8/14.5	30.2	0.002	0.000	0.002
60570005	CA	Nevada	6.3/9.6	25.4	0.000	0.000	0.000
60610003	CA	Placer #1	5/7.7	29.8	0.000	0.000	0.000
60610004	CA	Placer #2	0/5.1	24	0.000	0.000	0.000
60670012	CA	Sacramento	2.7/3.4	30.8	0.000	0.000	0.000
60990005	CA	Stanislaus	3.8/4.7	29.2	0.001	0.000	0.001
80350004	CO	Denver/Chatfield	-/0.2	15.6	0.055	0.001	0.056
80590006	CO	Rocky Flats	0.8/1.4	17.3	0.042	0.000	0.042
80590011	CO	Denver/NREL	1.7/2.4	17.6	0.044	0.001	0.044
490110004	UT	SLC/Bountiful	0.8/3	8	0.037	0.002	0.038
490353006	UT	SLC/Hawthorne	1.6/3.2	8.3	0.036	0.002	0.038
490353013	UT	SLC/Herriman	2.6/3.1	8.9	0.018	0.001	0.019
490570002	UT	SLC/Ogden	-/0.8	6.1	0.034	0.001	0.035

**Home state emission reductions are not assumed in this analysis.*

Table 4. For Tier 1 Industries and Impactful Boilers in Tier 2 Industries, By State And By Industry, Estimated Emissions Reductions (ozone season tons*) and Costs

		Tier 1		Tier 2	
State	Industry	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)
AR	Basic Chemical Manufacturing	-	-	87	$1.1 ($5,113)
AR	Glass and Glass Product Manufacturing	47	$0.2 ($2,046)	-	-
AR	Iron and Steel Mills and Ferroalloy Manufacturing	6	$0.0 ($631)	-	-
AR	Pipeline Transportation of Natural Gas	868	$10.1 ($4,852)	-	-
AR	Pulp, Paper, and Paperboard Mills	-	-	646	$6.1 ($3,967)
CA	Cement and Concrete Product Manufacturing	1,162	$3.6 ($1,279)	-	-
CA	Glass and Glass Product Manufacturing	299	$0.9 ($1,293)	-	-
CA	Petroleum and Coal Products Manufacturing	-	-	68	$0.4 ($2,349)
CA	Pipeline Transportation of Natural Gas	137	$1.5 ($4,718)	-	-
IL	Cement and Concrete Product Manufacturing	234	$0.7 ($1,279)	-	-
IL	Glass and Glass Product Manufacturing	901	$2.6 ($1,180)	-	-
IL	Pipeline Transportation of Natural Gas	1,316	$13.7 ($4,348)	-	-
IN	Cement and Concrete Product Manufacturing	468	$1.4 ($1,279)	-	-
IN	Glass and Glass Product Manufacturing	338	$1.7 ($2,046)	-	-
IN	Iron and Steel Mills and Ferroalloy Manufacturing	1,829	$16.0 ($3,653)	-	-
IN	Petroleum and Coal Products Manufacturing	-	-	388	$2.8 ($2,989)
IN	Pipeline Transportation of Natural Gas	152	$2.0 ($5,457)	-	-
KY	Pipeline Transportation of Natural Gas	2,291	$28.7 ($5,213)	-	-
LA	Basic Chemical Manufacturing	-	-	1,611	$15.2 ($3,939)
LA	Glass and Glass Product Manufacturing	206	$1.9 ($3,770)	-	-
LA	Petroleum and Coal Products Manufacturing	-	-	477	$4.0 ($3,498)
LA	Pipeline Transportation of Natural Gas	3,915	$44.3 ($4,720)	-	-
LA	Pulp, Paper, and Paperboard Mills	-	-	561	$5.2 ($3,830)
MD	Pipeline Transportation of Natural Gas	45	$0.3 ($3,042)	-	-
MI	Cement and Concrete Product Manufacturing	371	$1.1 ($1,279)	-	-
MI	Glass and Glass Product Manufacturing	50	$0.3 ($2,661)	-	-
MI	Iron and Steel Mills and Ferroalloy Manufacturing	38	$0.4 ($4,194)	-	-
MI	Pipeline Transportation of Natural Gas	2,272	$25.9 ($4,747)	-	-
MN	Glass and Glass Product Manufacturing	115	$0.6 ($2,288)	-	-
MN	Pipeline Transportation of Natural Gas	558	$7.3 ($5,452)	-	-
MO	Cement and Concrete Product Manufacturing	1,296	$4.0 ($1,279)	-	-
MO	Glass and Glass Product Manufacturing	227	$1.1 ($1,992)	-	-
MO	Pipeline Transportation of Natural Gas	1,581	$20.2 ($5,338)	-	-
MS	Pipeline Transportation of Natural Gas	1,577	$19.0 ($5,009)	-	-
MS	Pulp, Paper, and Paperboard Mills	-	-	184	$1.4 ($3,243)
NY	Cement and Concrete Product Manufacturing	142	$0.4 ($1,279)	-	-
NY	Glass and Glass Product Manufacturing	141	$0.5 ($1,572)	-	-
NY	Pipeline Transportation of Natural Gas	106	$1.2 ($4,697)	-	-
NY	Pulp, Paper, and Paperboard Mills	-	-	111	$1.2 ($4,486)

OH	Cement and Concrete Product Manufacturing	116	$0.4 ($1,279)	-	-
OH	Glass and Glass Product Manufacturing	451	$2.2 ($1,998)	-	-
OH	Iron and Steel Mills and Ferroalloy Manufacturing	847	$7.6 ($3,763)	-	-
OH	Pipeline Transportation of Natural Gas	1,198	$14.6 ($5,062)	-	-
OH	Pulp, Paper, and Paperboard Mills	-	-	179	$2.3 ($5,303)
OK	Cement and Concrete Product Manufacturing	586	$1.8 ($1,279)	-	-
OK	Glass and Glass Product Manufacturing	190	$1.2 ($2,550)	-	-
OK	Pipeline Transportation of Natural Gas	2,799	$34.1 ($5,083)	-	-
PA	Cement and Concrete Product Manufacturing	888	$2.8 ($1,336)	-	-
PA	Glass and Glass Product Manufacturing	1,379	$3.8 ($1,133)	-	-
PA	Iron and Steel Mills and Ferroalloy Manufacturing	438	$6.1 ($5,823)	-	-
PA	Petroleum and Coal Products Manufacturing	-	-	98	$0.6 ($2,349)
PA	Pipeline Transportation of Natural Gas	427	$4.1 ($3,994)	-	-
PA	Pulp, Paper, and Paperboard Mills	-	-	54	$0.9 ($7,019)
TX	Cement and Concrete Product Manufacturing	1,234	$7.8 ($2,624)	-	-
TX	Glass and Glass Product Manufacturing	1,470	$3.9 ($1,109)	-	-
TX	Pipeline Transportation of Natural Gas	1,736	$20.7 ($4,966)	-	-
UT	Cement and Concrete Product Manufacturing	520	$1.6 ($1,279)	-	-
UT	Pipeline Transportation of Natural Gas	237	$2.7 ($4,718)	-	-
VA	Cement and Concrete Product Manufacturing	398	$1.2 ($1,279)	-	-
VA	Glass and Glass Product Manufacturing	174	$0.9 ($2,154)	-	-
VA	Iron and Steel Mills and Ferroalloy Manufacturing	92	$1.0 ($4,357)	-	-
VA	Pipeline Transportation of Natural Gas	801	$10.5 ($5,457)	-	-
VA	Pulp, Paper, and Paperboard Mills	-	-	98	$1.4 ($5,903)
WI	Glass and Glass Product Manufacturing	677	$2.5 ($1,517)	-	-
WI	Pulp, Paper, and Paperboard Mills	-	-	1,472	$11.7 ($3,307)
WV	Cement and Concrete Product Manufacturing	230	$0.7 ($1,279)	-	-
WV	Pipeline Transportation of Natural Gas	751	$6.5 ($3,612)	-	-
WY	Cement and Concrete Product Manufacturing	446	$1.4 ($1,279)	-	-
WY	Pipeline Transportation of Natural Gas	380	$4.9 ($5,349)	-	-
	Grand Total	**41,153**	**$356.6 ($3,610)**	**6,033**	**$54.2 ($3,744)**

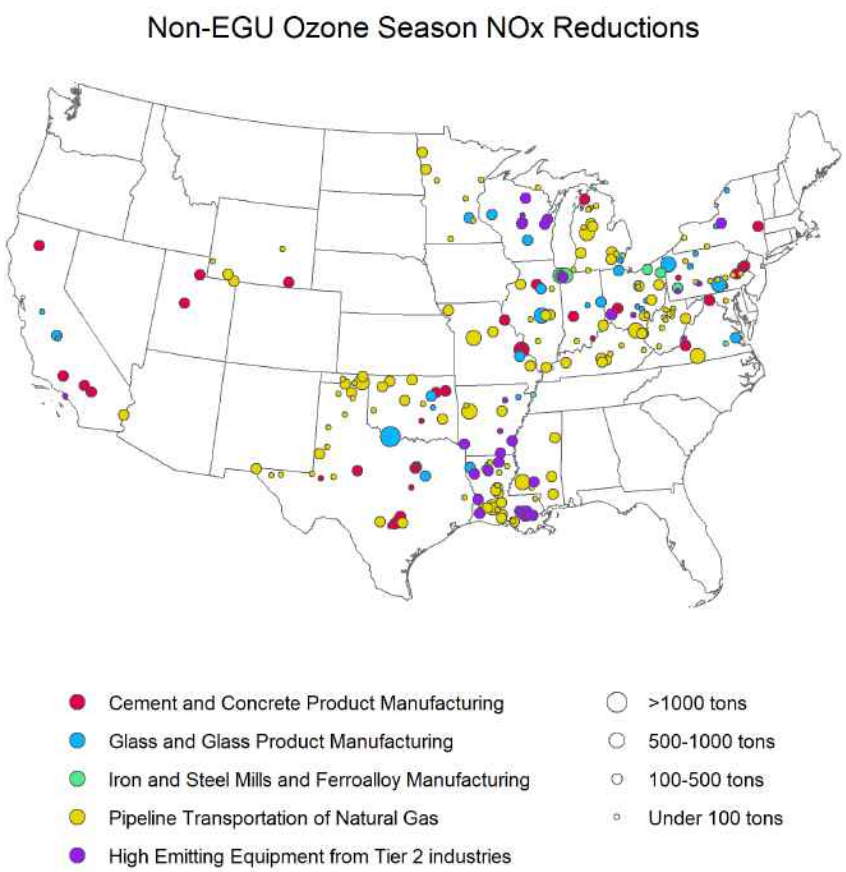
*Ozone season tons are calculated as tpy from the NEI multiplied by 5/12.

Note that New Jersey and Nevada did not have any estimated non-EGU reductions that cost up to $7,500 per ton from the Tier 1 industries and boilers in Tier 2 industries.

Table 4a. For Tier 1 Industries and Impactful Boilers in Tier 2 Industries, By State, Estimated Emissions Reductions (ozone season tons) and Costs

	Tier 1		Tier 2	
State	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)	Ozone Season Emissions Reductions	Annual Total Cost (million $) (Avg Annual Cost per Ton)
AR	922	$10.4 ($4,679)	732	$7.2 ($4,102)
CA	1,598	$6.0 ($1,576)	68	$0.4 ($2,349)
IL	2,452	$17.0 ($2,890)	-	-
IN	2,787	$21.1 ($3,157)	388	$2.8 ($2,989)
KY	2,291	$28.7 ($5,213)	-	-
LA	4,121	$46.2 ($4,673)	2,649	$24.4 ($3,837)
MD	45	$0.3 ($3,042)	-	-
MI	2,731	$27.7 ($4,230)	-	-
MN	673	$7.9 ($4,910)	-	-
MO	3,103	$25.3 ($3,399)	-	-
MS	1,577	$19.0 ($5,009)	184	$1.4 ($3,243)
NY	389	$2.2 ($2,316)	111	$1.2 ($4,486)
OH	2,611	$24.7 ($3,944)	179	$2.3 ($5,303)
OK	3,575	$37.1 ($4,325)	-	-
PA	3,132	$16.8 ($2,237)	152	$1.5 ($4,013)
TX	4,440	$32.4 ($3,038)	-	-
UT	757	$4.3 ($2,356)	-	-
VA	1,465	$13.6 ($3,861)	98	$1.4 ($5,903)
WI	677	$2.5 ($1,517)	1,472	$11.7 ($3,307)
WV	982	$7.2 ($3,065)	-	-
WY	826	$6.2 ($3,152)	-	-

Figure 2. Geographical Distribution of Ozone Season NOx Reductions and Summary of Reductions by Industry and by State



State	Cement and Concrete Product Manufacturing	Glass and Glass Product Manufacturing	Iron and Steel Mills and Ferroalloy Manufacturing	Pipeline Transportation of Natural Gas	High Emitting Equipment from Tier 2 industries	Total
LA	0	206	0	3,915	2,649	6,769
TX	1,234	1,470	0	1,736	0	4,440
OK	586	190	0	2,799	0	3,575
PA	888	1,379	438	427	152	3,284
IN	468	338	1,829	152	388	3,175
MO	1,296	227	0	1,581	0	3,103
OH	116	451	847	1,198	179	2,790
MI	371	50	38	2,272	0	2,731
IL	234	901	0	1,316	0	2,452
KY	0	0	0	2,291	0	2,291
WI	0	677	0	0	1,472	2,150
MS	0	0	0	1,577	184	1,761
CA	1,162	299	0	137	68	1,666
AR	0	47	6	868	732	1,654
VA	398	174	92	801	98	1,563
WV	230	0	0	751	0	982
WY	446	0	0	380	0	826
UT	520	0	0	237	0	757
MN	0	115	0	558	0	673
NY	142	141	0	106	111	500
MD	0	0	0	45	0	45

Table 5. By Industry, Number and Type of Emissions Units, Total Estimated Emissions Reductions (ozone season tons), Total PPB Improvements, and Costs

		Number of Units by Type			Ozone Season Emissions Reductions (tons) by Type of Unit			Total PPB Improvement Across Downwind Receptors (Max Improvement At Receptor)		Annual Total Cost (million $) (Avg Annual Cost per Ton)
Industry	Region	Boilers	Internal Combustion Engines	Industrial Processes	Boilers	Internal Combustion Engines	Industrial Processes	East	West	
Glass and Glass Product Manufacturing	East	-	-	41	-	-	6,367	0.6962 (0.0865)	0.0015 (0.0004)	$23.2 ($1,520)
	West	-	-	3	-	-	299	0.0009 (0.0001)	0.0332 (0.0066)	$0.9 ($1,293)
Cement and Concrete Product Manufacturing	East	1	-	39	16	-	5,948	0.6382 (0.0707)	0.0018 (0.0006)	$22.4 ($1,566)
	West	-	-	8	-	-	2,128	0.0151 (0.0019)	0.1996 (0.0332)	$6.5 ($1,279)
Iron and Steel Mills and Ferroalloy Manufacturing	East	25	-	15	2,044	-	1,207	1.1556 (0.1750)	0.0000 (0.0000)	$31.2 ($3,995)
Pipeline Transportation of Natural Gas	East	-	296	-	-	22,390	-	1.5373 (0.2815)	0.0057 (0.0020)	$263.2 ($4,898)
	West	-	11	-	-	754	-	0.0086 (0.0010)	0.0586 (0.0170)	$9.1 ($5,037)
Basic Chemical Manufacturing	East	17	-	-	1,698	-	-	0.1655 (0.0107)	0.0002 (0.0000)	$16.3 ($3,999)
Petroleum and Coal Products Manufacturing	East	9	-	-	962	-	-	0.2677 (0.0258)	0.0000 (0.0000)	$7.3 ($3,176)
	West	1	-	-	68	-	-	0.0002 (0.0000)	0.0075 (0.0015)	$0.4 ($2,349)
Pulp, Paper, and Paperboard Mills	East	25	-	-	3,305	-	-	0.3678 (0.0117)	0.0002 (0.0000)	$30.2 ($3,807)

Blue highlights reflect western states information.
Orange highlights reflect Tier 2 industries with impactful boilers.

Table 6. By Industry, Emissions Source Group, Control Technology, Number of Units, Estimated Emissions Reductions (ozone season tons), and Annual Total Cost

Industry	Emissions Source Group	Control Technology	Number of Units	Ozone Season Emissions Reductions	Annual Total Cost (million $)
Cement and Concrete Product Manufacturing	Boilers - < 10 Million BTU/hr; Industrial Processes - Kiln	Ultra Low NOx Burner; Selective Non-Catalytic Reduction	1	117	$0.5
	Industrial Processes - Kiln	Selective Non-Catalytic Reduction	24	3,123	$9.7
	Industrial Processes - Preheater Kiln	Selective Non-Catalytic Reduction	3	342	$1.2
	Industrial Processes - Preheater/Precalciner Kiln	Selective Non-Catalytic Reduction	19	4,510	$17.5
Glass and Glass Product Manufacturing	Industrial Processes - Container Glass: Melting Furnace	Selective Catalytic Reduction	27	1,676	$8.7
	Industrial Processes - Flat Glass: Melting Furnace	Selective Catalytic Reduction	13	4,674	$12.7
	Industrial Processes - Furnace: General	Oxygen Enriched Air Staging	1	52	$0.1
	Industrial Processes - Pressed and Blown Glass: Melting Furnace	Selective Catalytic Reduction	3	264	$2.7
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	3	383	$4.2
	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	6	282	$2.2
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	2	106	$1.2
	Boilers - > 100 Million BTU/hr; Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	166	$1.0
	Boilers - > 100 Million BTU/hr; Boilers - Coke Oven Gas	Ultra Low NOx Burner	6	360	$2.9
	Boilers - > 100 Million BTU/hr; Boilers - Coke Oven Gas	Selective Catalytic Reduction; Ultra Low NOx Burner and Selective Catalytic Reduction	1	114	$1.7
	Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	65	$0.4
	Boilers - Blast Furnace Gas; Industrial Processes - Sintering: Windbox; Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation; Industrial Processes - Process Gas: Process Heaters	Ultra Low NOx Burner; Selective Catalytic Reduction; Low NOx Burner and Flue Gas Recirculation	1	440	$4.4
	Boilers - Coke Oven Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	3	394	$3.7
	Boilers - Coke Oven Gas; Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner; Ultra Low NOx Burner and Selective Catalytic Reduction	1	116	$1.6
	Industrial Processes - Basic Oxygen Furnace (BOF): Open Hood Stack	Selective Catalytic Reduction	2	185	$1.9
	Industrial Processes - Basic Oxygen Furnace (BOF): Open Hood Stack; Industrial Processes - General	Selective Catalytic Reduction; Low NOx Burner	1	172	$1.7
	Industrial Processes - Basic Oxygen Furnace (BOF): Top Blown Furnace: Primary	Selective Catalytic Reduction	1	50	$0.5
	Industrial Processes - Blast Furnace: Casting/Tapping: Local Evacuation	Selective Catalytic Reduction	1	38	$0.4
	Industrial Processes - General	Low NOx Burner	5	191	$1.7
	Industrial Processes - General; Industrial Processes - Coke Oven or Blast Furnace	Low NOx Burner; Low NOx Burner and Flue Gas Recirculation	1	84	$1.0
	Industrial Processes - Other Not Classified	Low NOx Burner and Flue Gas Recirculation	2	43	$0.1
	Industrial Processes - Sintering: Windbox	Selective Catalytic Reduction	1	60	$0.6
Pipeline Transportation of Natural Gas	Internal Combustion Engines - 2-cycle Clean Burn	Layered Combustion	1	60	$0.8
	Internal Combustion Engines - 2-cycle Lean Burn	Layered Combustion	136	12,645	$165.6
	Internal Combustion Engines - 4-cycle Lean Burn	Selective Catalytic Reduction	41	2,656	$21.6
	Internal Combustion Engines - 4-cycle Rich Burn	Non-Selective Catalytic Reduction	2	147	$0.2
	Internal Combustion Engines - Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion	94	6,329	$72.0
	Internal Combustion Engines - Reciprocating	Adjust Air to Fuel Ratio and Ignition Retard	12	193	$1.1
	Internal Combustion Engines - Reciprocating	Non-Selective Catalytic Reduction or Layered Combustion; Adjust Air to Fuel Ratio and Ignition Retard	1	49	$0.4
	Internal Combustion Engines - Turbine	Selective Catalytic Reduction and Steam Injection	17	929	$8.4
	Internal Combustion Engines - Turbine	SCR + DLN Combustion	3	136	$2.1

Basic Chemical Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	6	786	$7.5
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	2	104	$1.5
	Boilers - 10-100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	1	133	$1.0
	Boilers - 10-100 Million BTU/hr	Selective Catalytic Reduction	1	43	$0.1
	Boilers - Cogeneration	Selective Catalytic Reduction	1	68	$0.9
	Boilers - Distillate Oil - Grades 1 and 2: Boiler	Selective Catalytic Reduction	1	47	$0.6
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	2	293	$2.8
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner	2	138	$0.8
	Boilers - Subbituminous Coal: Traveling Grate (Overfeed) Stoker	Selective Catalytic Reduction	1	87	$1.1
Petroleum and Coal Products Manufacturing	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	1	41	$0.2
	Boilers - > 100 Million BTU/hr; Boilers - Blast Furnace Gas	Ultra Low NOx Burner	1	38	$0.4
	Boilers - Boiler, >= 100 Million BTU/hr	Natural Gas Reburn	1	284	$1.8
	Boilers - Coke Oven Gas	Ultra Low NOx Burner	1	98	$0.6
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	3	433	$3.8
	Boilers - Petroleum Refinery Gas	Ultra Low NOx Burner	3	137	$0.9
Pulp, Paper, and Paperboard Mills	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner and Selective Catalytic Reduction	5	618	$6.8
	Boilers - > 100 Million BTU/hr	Ultra Low NOx Burner	3	151	$1.0
	Boilers - > 100 Million BTU/hr	Selective Catalytic Reduction	1	68	$1.2
	Boilers - 10-100 Million BTU/hr	Ultra Low NOx Burner	2	106	$0.5
	Boilers - Bituminous Coal: Cyclone Furnace	Selective Catalytic Reduction	2	662	$3.4
	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom	Ultra Low NOx Burner and Selective Catalytic Reduction	1	111	$1.1
	Boilers - Bituminous Coal: Pulverized Coal: Dry Bottom; Boilers - > 100 Million BTU/hr	Low NOx Burner; Selective Catalytic Reduction	1	98	$1.4
	Boilers - Bituminous Coal: Spreader Stoker	Selective Catalytic Reduction	3	251	$3.2
	Boilers - Cogeneration	Ultra Low NOx Burner and Selective Catalytic Reduction	2	338	$2.9
	Boilers - Fluid Catalytic Cracking Unit with CO Boiler: Natural Gas	Ultra Low NOx Burner and Selective Catalytic Reduction	2	289	$2.7
	Boilers - Subbituminous Coal: Boiler, Spreader Stoker	Selective Catalytic Reduction	2	348	$3.7
	Boilers - Subbituminous Coal: Spreader Stoker	Selective Catalytic Reduction	1	266	$2.3

Table 7. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across All Non-EGU Emissions Units

Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Layered Combustion	12,706	$166,398,282	$5,457
Low NOx Burner	231	$2,092,579	$3,773
Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Natural Gas Reburn	284	$1,843,948	$2,703
Non-Selective Catalytic Reduction	147	$205,808	$585
Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Oxygen Enriched Air Staging	52	$95,641	$764
SCR + DLN Combustion	136	$2,060,943	$6,301
Selective Catalytic Reduction	12,239	$74,692,132	$2,543
Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Ultra Low NOx Burner	1,670	$11,584,405	$2,890
Ultra Low NOx Burner and Selective Catalytic Reduction	3,946	$38,959,490	$4,114

Table 8. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across Non-EGU Emissions Units Grouped by the Tier 1 Industries and Impactful Boilers in Tier 2 Industries

Tier	Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Tier 1	Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Tier 1	Layered Combustion	12,706	$166,398,282	$5,457
Tier 1	Low NOx Burner	211	$1,852,495	$3,656
Tier 1	Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Tier 1	Non-Selective Catalytic Reduction	147	$205,808	$585
Tier 1	Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Tier 1	Oxygen Enriched Air Staging	52	$95,641	$764
Tier 1	SCR + DLN Combustion	136	$2,060,943	$6,301
Tier 1	Selective Catalytic Reduction	10,219	$55,575,188	$2,266
Tier 1	Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Tier 1	Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Tier 1	Ultra Low NOx Burner	962	$7,172,778	$3,107
Tier 1	Ultra Low NOx Burner and Selective Catalytic Reduction	946	$10,362,549	$4,567
Tier 2	Low NOx Burner	20	$240,084	$5,022
Tier 2	Natural Gas Reburn	284	$1,843,948	$2,703
Tier 2	Selective Catalytic Reduction	2,020	$19,116,944	$3,942
Tier 2	Ultra Low NOx Burner	708	$4,411,626	$2,594
Tier 2	Ultra Low NOx Burner and Selective Catalytic Reduction	3,000	$28,596,941	$3,972

Table 9. Estimated Emissions Reductions (ozone season tons), Annual Total Cost, and Average Cost per Ton by Control Technology Across Non-EGU Emissions Units Grouped by the Seven Individual Tier 1 and Tier 2 Industries

Industry	Control Technology	OS NOx Reductions	Annual Total Cost	Average Cost per Ton
Cement and Concrete Product Manufacturing	Selective Non-Catalytic Reduction	8,076	$28,782,335	$1,485
Cement and Concrete Product Manufacturing	Ultra Low NOx Burner	16	$169,531	$4,410
Glass and Glass Product Manufacturing	Oxygen Enriched Air Staging	52	$95,641	$764
Glass and Glass Product Manufacturing	Selective Catalytic Reduction	6,615	$24,062,362	$1,516
Iron and Steel Mills and Ferroalloy Manufacturing	Low NOx Burner	211	$1,852,495	$3,656
Iron and Steel Mills and Ferroalloy Manufacturing	Low NOx Burner and Flue Gas Recirculation	200	$2,054,876	$4,288
Iron and Steel Mills and Ferroalloy Manufacturing	Selective Catalytic Reduction	948	$9,886,092	$4,345
Iron and Steel Mills and Ferroalloy Manufacturing	Ultra Low NOx Burner	946	$7,003,247	$3,085
Iron and Steel Mills and Ferroalloy Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	946	$10,362,549	$4,567
Pipeline Transportation of Natural Gas	Adjust Air to Fuel Ratio and Ignition Retard	212	$1,216,435	$2,393
Pipeline Transportation of Natural Gas	Layered Combustion	12,706	$166,398,282	$5,457
Pipeline Transportation of Natural Gas	Non-Selective Catalytic Reduction	147	$205,808	$585
Pipeline Transportation of Natural Gas	Non-Selective Catalytic Reduction or Layered Combustion	6,359	$72,383,222	$4,743
Pipeline Transportation of Natural Gas	SCR + DLN Combustion	136	$2,060,943	$6,301
Pipeline Transportation of Natural Gas	Selective Catalytic Reduction	2,656	$21,626,734	$3,393
Pipeline Transportation of Natural Gas	Selective Catalytic Reduction and Steam Injection	929	$8,439,921	$3,787
Basic Chemical Manufacturing	Selective Catalytic Reduction	348	$4,198,768	$5,027
Basic Chemical Manufacturing	Ultra Low NOx Burner	138	$769,564	$2,317
Basic Chemical Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	1,211	$11,326,715	$3,896
Petroleum and Coal Products Manufacturing	Natural Gas Reburn	284	$1,843,948	$2,703
Petroleum and Coal Products Manufacturing	Ultra Low NOx Burner	313	$2,110,773	$2,808
Petroleum and Coal Products Manufacturing	Ultra Low NOx Burner and Selective Catalytic Reduction	433	$3,762,867	$3,624
Pulp, Paper, and Paperboard Mills	Low NOx Burner	20	$240,084	$5,022
Pulp, Paper, and Paperboard Mills	Selective Catalytic Reduction	1,672	$14,918,176	$3,717
Pulp, Paper, and Paperboard Mills	Ultra Low NOx Burner	257	$1,531,289	$2,484
Pulp, Paper, and Paperboard Mills	Ultra Low NOx Burner and Selective Catalytic Reduction	1,356	$13,507,360	$4,151

VI. Request for Comment and Additional Information

In this screening assessment the EPA used CoST, the CMDB, and the 2019 emissions inventory to assess emission reduction potential from non-EGU emissions units in several industries. We identified emissions units that were uncontrolled or that could be better controlled and then applied control technologies to estimate emissions reductions and costs. As noted above, the cost estimates do not include monitoring, recordkeeping, reporting, or testing costs.

As discussed in Section VI.D.2.a of the proposal preamble, the EPA requests comment on the capital and annual costs of several potential control technologies, and in particular whether ultra-low NO_X burners or low NO_X burners are generally considered part of the process or add-on controls for ICI boilers (and how process changes or retrofits to accommodate controls would affect the cost estimates); the effectiveness of low emissions combustion in controlling NO_X from reciprocating IC engines, compared to other potential NO_X controls for these engines; and whether controls on ICI boilers and reciprocating IC engines are likely to be run all year or only during the ozone season.

The EPA also requests comment on the time needed to install the various control technologies across all of the emissions units in the Tier 1 and Tier 2 industries. In particular, the EPA solicits comment on the time needed to obtain permits, the availability of vendors and materials, and the earliest possible installation times for SCR on glass furnaces; SNCR on cement kilns; ultra-low NO_X burners, low NO_X burners, and SCR on ICI boilers (coal-fired, gas-fired, or oil-fired); low NO_X burners on large non-EGU ICI boilers; and low emissions combustion, layered emissions combustion, NSCR, and SCR on reciprocating rich-burn or lean-burn IC engines.

Finally, with respect to emissions monitoring requirements, the EPA requests comment on the costs of installing and operating CEMS at non-EGU sources without NO_X emissions monitors; the time needed to program and install CEMS at non-EGU sources; whether monitoring techniques other than CEMS, such as predictive emissions monitoring systems (PEMS), may be sufficient for certain non-EGU facilities, and the types of non-EGU facilities for which such PEMS may be sufficient; and the costs of installing and operating monitoring techniques other than CEMS.

APPENDIX A – Analysis of Industry Contribution Data

This appendix describes the analyses performed to help focus the non-EGU analytical framework and resulting screening assessment on the most impactful industries.

To inform this analysis, first using the procedure described in Section III, Step 1 above, we estimated contributions from each of 41 industries to each nonattainment and maintenance receptor in 2023 and used these data to calculate the 5 metrics identified in Table A-1.[27,28] A summary of the data for each metric for each industry is provided in Table A-3. These metrics were selected to provide air quality information to inform an evaluation of the magnitude and geographic scope of contributions from individual industries. Metrics 1, 2, and 3 provide information on the magnitude of the contribution. Metric 4 provides information on the geographic scope of the downwind impact, whereas Metric 5 provides information on the geographic scope of upwind state contributions. Of the three air quality metrics we chose to analyze the data for Metric 2, the maximum contribution to any downwind receptor, because this metric aligns with the air quality metric used in Step 2 of the four-step interstate transport framework to identify linked upwind states for further review in Step 3 of the interstate transport framework. To examine the geographic breadth of the industry contributions we chose Metric 4 because that metric provides information on the extent of impacts on downwind air quality problems.

Table A-1. Contribution Metrics for Non-EGU Assessment

1	Total contribution to all downwind receptors
2	Maximum contribution to any downwind receptor
3	Average contribution across all receptors
4	Number of receptors with contributions >= 0.01 ppb
5	Number of linked upwind states with highest industry contribution >= 0.01 ppb

Next, we evaluated the maximum downwind contributions to identify the most impactful industries for further analysis. This approach included a semi-quantitative examination of rank-ordered maximum contributions to identify breakpoints in the data that might serve as an initial screen to eliminate non-impactful industries from further analysis of the contribution data. The distribution of maximum contributions provided in Table A-3 indicate that there is a large range in the values across the 41 industries. Specifically, 5 industries individually contribute more than 0.10 ppb, 3 industries contribute between 0.05 ppb and 0.10 ppb, 11 industries contribute between 0.01 and 0.05 ppb, 8 industries contribution between 0.005 and 0.01 ppb, and 14 industries contribute less than 0.005 ppb.

The rank-ordered maximum downwind contributions from individual industries are shown in Figure A-1. In this figure each point represents the maximum contribution to a downwind receptor from a particular industry. Note that the values for the highest contributing industries are not show in the figure in order to provide greater resolution of the shape of the distribution at the lower end of the values. The declining curve in Figure A-1 exhibits a shape similar to a harmonic distribution. Initially, there is a fairly steep drop in contributions with a breakpoint between roughly 0.04 and 0.06 ppb followed by a steady decline to 0.01 ppb. Beyond 0.01 ppb the shape of the distribution is much flatter. The data suggest that perhaps 0.05 ppb or 0.01 ppb could serve as breakpoints in the data. Based on the distribution

[27] Receptors in California were not considered in evaluating the impacts of non-EGU sources because EPA's contributions from upwind states to these receptors at Step 2 of the four-step interstate transport framework finds that these monitoring sites are overwhelmingly impacted by in-state emissions to a degree not comparable with any other identified nonattainment or maintenance-only receptors in the country. In this regard, EPA is proposing a determination that California receptors are not sufficiently impacted by interstate transport of ozone to warrant proceeding with a Step 3 evaluation of emissions reduction opportunities.

[28] The methods for identifying receptors are described in the Air Quality Modeling TSD for this proposed rule.

of the data we determined that 0.01 ppb provides a meaningful conservative breakpoint for screening out non-impactful industries from the non-EGU contribution analysis. The specific industries with a maximum downwind contribution >= 0.01 ppb are identified in Table A-2.

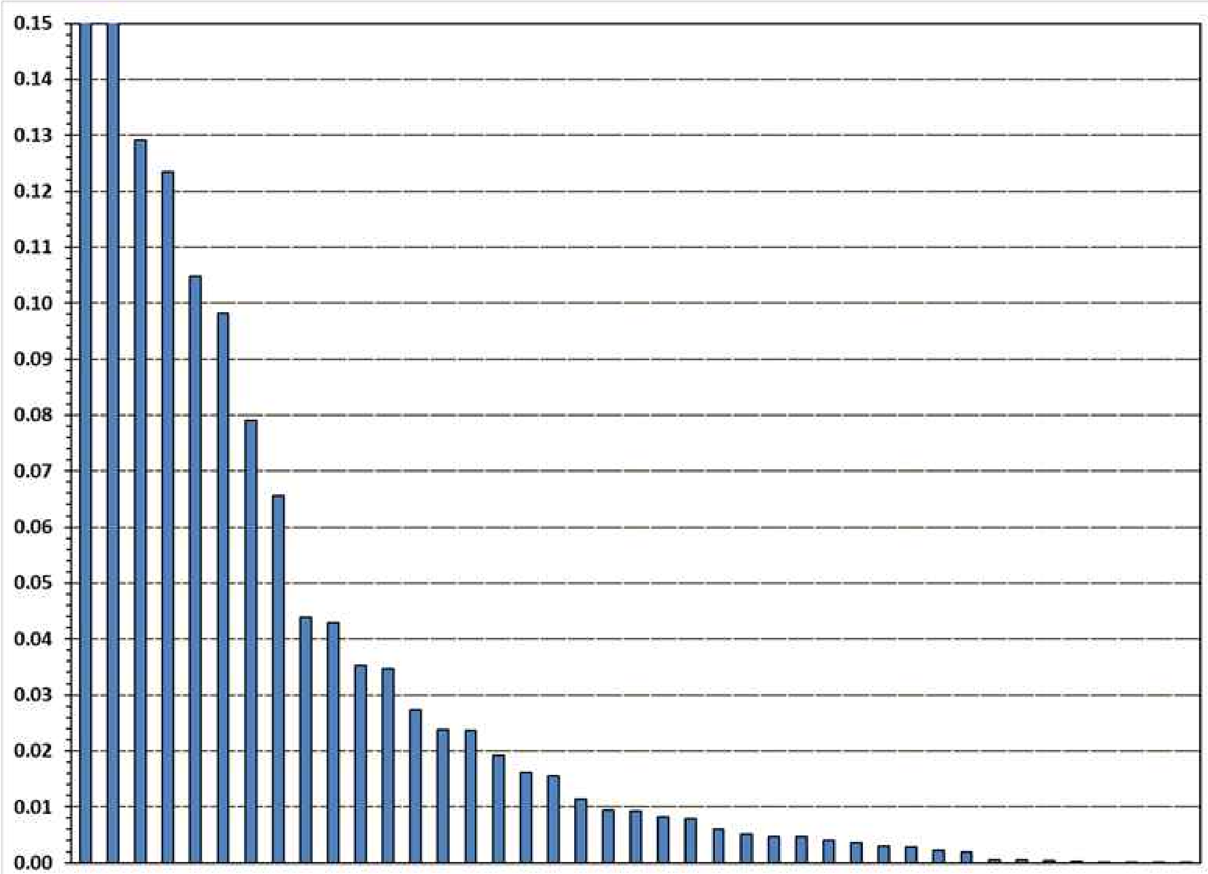


Figure A-1. Rank-ordered maximum downwind contributions from individual industries

We then examined the data for Metrics 2 and 4 for each industry that has a maximum contribution >= 0.01 ppb. The data for Metric 4, as shown in Figure A-2, suggests that there as a breakpoint between those industries that contribute to 10 or more receptors versus those industries that contribute to fewer than 10 receptors. Table A-2 provides the data for Metrics 2 and 4, ranked by the magnitude of Metric 4. The data show that 8 industries contribute >= 0.01 ppb to more than 10 receptors. Of these 8 industries, 5 have a maximum contributions of > 0.10 ppb to one of these receptors. In addition, one industry, Basic Chemical Manufacturing, contributes to only 9 receptors, but the maximum contribution to one of these receptors is >0.10 ppb. Using this information, we grouped the 9 industries into one of 2 tiers based on considering both the magnitude of the contribution and the downwind extent of affected receptors. Tier 1 includes the 4 industries that each have (1) a maximum contribution to any one receptor of >0.10 ppb and (2) a contribution >= 0.01 ppb to at least 10 receptors. Tier 2 includes the 5 industries that each have (1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or (2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors.

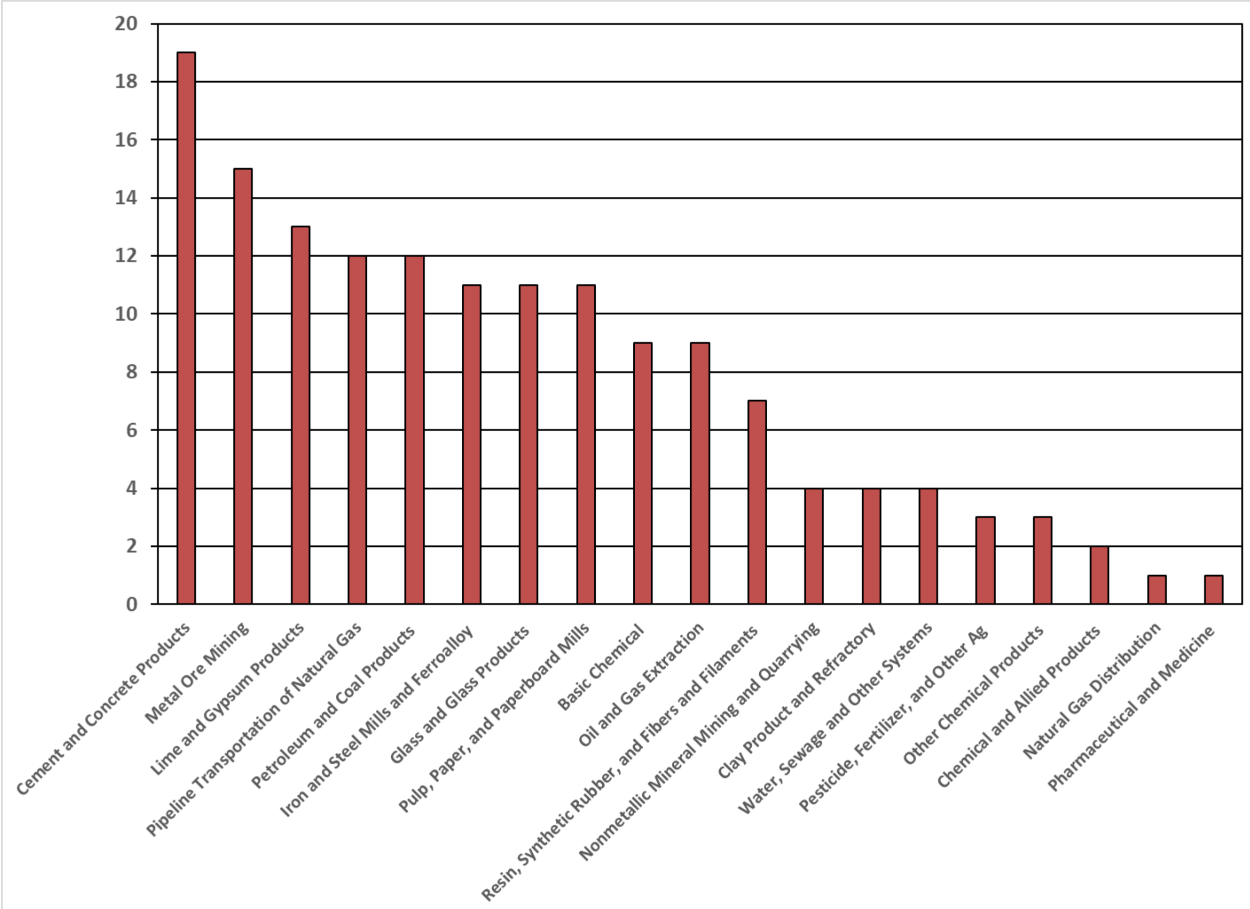


Figure A-2. Number of downwind receptors with contributions >= 0.10 ppb for each industry with a maximum downwind contribution >= 0.01 ppb

Table A-2. Maximum downwind contribution and number of receptors with contributions >= 0.01 ppb

Industry	Max Downwind Contribution	# Receptors with Contributions >= 0.01 ppb
Cement and Concrete Products	**0.231**	**19**
Metal Ore Mining	0.079	**15**
Lime and Gypsum Products	0.066	**13**
Pipeline Transportation of Natural Gas	**0.287**	**12**
Petroleum and Coal Products	0.098	**12**
Iron and Steel Mills and Ferroalloy	**0.129**	**11**
Glass and Glass Products	**0.105**	**11**
Pulp, Paper, and Paperboard Mills	0.043	**11**
Basic Chemical	**0.123**	9
Oil and Gas Extraction	0.035	9
Resin, Synthetic Rubber, and Fibers and Filaments	0.027	7
Nonmetallic Mineral Mining and Quarrying	0.035	4
Clay Product and Refractory	0.024	4
Water, Sewage and Other Systems	0.016	4
Pesticide, Fertilizer, and Other Ag	0.044	3
Other Chemical Products	0.024	3
Chemical and Allied Products	0.019	2
Natural Gas Distribution	0.016	1
Pharmaceutical and Medicine	0.011	1

Table A-3. Estimated Total, Maximum, and Average Contributions from Each Industry, and Number of Receptors with Contributions >= 0.01 ppb for 2023

Industry	# Facilities with Units > 100tpy	# Units > 100 tpy	Ozone Season Emissions	Total Contribution	Max Contribution	Average Contribution	# Receptors with Contributions >= 0.01 ppb	# States with Highest Contribution >= 0.01 ppb
Pipeline Transportation of Natural Gas	144	399	34,343	**1.679**	**0.287**	**0.084**	**12**	**12**
Cement and Concrete Product Manufacturing	61	84	36,244	**1.871**	**0.231**	**0.094**	**19**	**13**
Iron and Steel Mills and Ferroalloy Manufacturing	14	43	4,622	**0.577**	**0.129**	**0.029**	**11**	1
Basic Chemical Manufacturing	38	78	9,612	**0.293**	**0.123**	**0.015**	**9**	**2**
Glass and Glass Product Manufacturing	38	53	12,059	**0.695**	**0.105**	**0.035**	**11**	**7**
Petroleum and Coal Products Manufacturing	47	94	8,163	**0.733**	**0.098**	**0.037**	**12**	**6**
Metal Ore Mining	9	21	17,778	**0.687**	**0.079**	**0.034**	**15**	**3**
Lime and Gypsum Product Manufacturing	31	60	8,856	**0.531**	**0.066**	**0.027**	**13**	**3**
Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing	16	27	3,680	**0.162**	**0.044**	0.008	**3**	1
Pulp, Paper, and Paperboard Mills	46	73	6,773	**0.306**	**0.043**	**0.015**	**11**	**3**
Oil and Gas Extraction	59	139	9,150	**0.207**	**0.035**	**0.010**	**9**	**2**
Nonmetallic Mineral Mining and Quarrying	8	18	3,808	**0.167**	**0.035**	0.008	**4**	1
Resin, Synthetic Rubber, and Artificial and Synthetic Fibers and Filaments Manufacturing	10	16	1,779	**0.152**	**0.027**	0.008	**7**	**2**
Other Chemical Product and Preparation Manufacturing	7	8	683	**0.074**	**0.024**	0.004	**3**	1
Clay Product and Refractory Manufacturing	1	2	1,098	**0.088**	**0.024**	0.004	**4**	1
Chemical and Allied Products Merchant Wholesalers	1	4	573	**0.032**	**0.019**	0.002	**2**	1
Natural Gas Distribution	6	17	1,027	**0.058**	**0.016**	0.003	1	1
Water, Sewage and Other Systems	6	6	375	**0.069**	**0.016**	0.003	**4**	1
Pharmaceutical and Medicine Manufacturing	2	2	300	**0.057**	**0.011**	0.003	1	1
Grain and Oilseed Milling	4	4	376	**0.042**	0.009	0.002	0	0
Lessors of Real Estate	2	2	138	**0.037**	0.009	0.002	0	0
Nonferrous Metal (except Aluminum) Production and Processing	1	4	408	**0.025**	0.008	0.001	0	0
Sugar and Confectionery Product Manufacturing	5	10	1,068	**0.043**	0.008	0.002	0	0
Electric Power Generation, Transmission and Distribution	4	4	296	**0.039**	0.006	0.002	0	0
Engine, Turbine, and Power Transmission Equipment Manufacturing	2	2	112	**0.020**	0.005	0.001	0	0
Agriculture, Construction, and Mining Machinery Manufacturing	1	1	73	**0.012**	0.005	0.001	0	0
Colleges, Universities, and Professional Schools	4	4	263	**0.030**	0.005	0.002	0	0
Coal Mining	5	5	283	**0.015**	0.004	0.001	0	0
Plastics Product Manufacturing	2	2	126	**0.012**	0.004	0.001	0	0
Architectural, Engineering, and Related Services	2	2	117	**0.013**	0.003	0.001	0	0
Motor Vehicle Parts Manufacturing	1	1	62	**0.011**	0.003	0.001	0	0
Advertising, Public Relations, and Related Services	1	1	51	0.009				
Waste Treatment and Disposal	5	5	376	0.010				
National Security and International Affairs	1	1	42	0.002				
Support Activities for Mining	1	1	56	0.003				
Beverage Manufacturing	1	1	45	0.002				
Veneer, Plywood, and Engineered Wood Product Manufacturing	1	1	9	0.001				
Scientific Research and Development Services	1	1	78	0.001				
Alumina and Aluminum Production and Processing	1	1	13	0.000				
Other Food Manufacturing	1	1	45	0.000				
Office Administrative Services	1	1	5	0.000				
Total	591	1,199	164,962	8.77				
Tier 1 Industries	257	579	87,267	4.82				
Tier 2 Industries	171	326	51,182	2.55				
Tier 1 Industries (% of Total)	43%	48%	53%	55%				
Tier 2 Industries (% of Total)	29%	27%	31%	29%				

Legend

	Maximum Contribution	# Receptors with Contributions >=0.01 ppb	Total Contribution	# States with Highest Contribution >= 0.01
Break Points	0.01 to 0.04	> 1 to 9	0.1 to 0.4	> 1 to 9
	>= 0.05	>= 10	>= 0.5	>= 10

1st Tier of Industries for Further Analysis Based on AQ Contributions

These industries (1) have a maximum contribution to any one receptor of >0.10 ppb AND (2) contribute >= 0.01 ppb to at least 10 receptors.

2nd Tier of Industries for Further Analysis Based on AQ Contributions

These industries either have:

(1) a maximum contribution to any one receptor >=0.10 ppb but contribute >=0.01 ppb to fewer than 10 receptors, or

(2) a maximum contribution <0.10 ppb but contribute >=0.01 ppb to at least 10 receptors

APPENDIX B – SUMMARY OF FACILITIES REMOVED in the SCREENING ASSESSMENT for 2026

REGION_CD	FACILITY_ID	Reason for Removal	state	county	site_name	naics_code	naics_description	city
24001	7763811	Closure	MD	Allegany	Luke Paper Company	322121	Paper (except Newsprint) Mills	Luke
06029	4789011	Subject to Consent Decree	CA	Kern	LEHIGH SOUTHWEST CEMENT CO.	327310	Cement Manufacturing	MONOLITH
06029	4789311	Subject to Consent Decree	CA	Kern	CALIFORNIA PORTLAND CEMENT CO.	327310	Cement Manufacturing	MOJAVE
06071	4841311	Subject to Consent Decree	CA	San Bernardino	CEMEX - BLACK MOUNTAIN QUARRY PLANT	327310	Cement Manufacturing	APPLE VALLEY
18093	8225311	Units to be replaced by new kiln by 2023	IN	Lawrence	LEHIGH CEMENT COMPANY LLC	32731	Cement Manufacturing	Mitchell
26007	8127411	Subject to Consent Decree	MI	Alpena	Holcim (US) Inc. DBA Lafarge Alpena Plant	327310	Cement Manufacturing	ALPENA

Motion to Stay, *United States Steel Corporation v. EPA, et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit F

Petition for Reconsideration and Stay, EPA-HQ-OAR-2021-0663-0091 (April 14, 2023)

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April 14, 2023

VIA E-MAIL AND FEDERAL EXPRESS

Michael Regan, Administrator
Environmental Protection Agency
Office of the Administrator, Mail Code 1101A
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023)

Dear Administrator Regan:

On behalf of our clients, ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively the "Minnesota Good Neighbor Coalition"), please find enclosed a petition for reconsideration and stay of the disapproval of "prong 2" of Minnesota's State Implementation Plan ("SIP") in the United States Environmental Protection Agency's final rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023).

Please contact me with any questions you may have.

Sincerely,

/s/ Douglas A. McWilliams
Douglas A. McWilliams

cc: Olivia Davidson
Debra Shore
Gautam Srinivasan
Thomas Uher

Before the United States Environmental Protection Agency

In re: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023)	))))))	EPA Docket Nos. EPA–HQ–OAR–2021–0663; EPA–R05–OAR–2022–0006; FRL–10209–01–OAR

Petition for Reconsideration and for Stay of the Air Plan Disapprovals for Interstate Transportation of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively "Petitioners") respectfully request that the United States Environmental Protection Agency ("EPA") reconsider and stay the portion of its final rule Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023) (the "SIP Disapproval") that disapproves Minnesota's state implementation plan ("SIP") for interstate transport for "prong 2" of Clean Air Act ("CAA") § 110(a)(2)(D)(i)(I), 42 U.S.C. § 7410(a)(2)(D)(i)(I).

Minnesota is uniquely situated in the SIP Disapproval. In EPA's February 13 action, Minnesota's SIP was approved for "prong 1"[1] based on EPA's finding that Minnesota does not contribute significantly to nonattainment in any downwind state. Minnesota's SIP was disapproved for "prong 2," with EPA finding that Minnesota was linked to interference with maintenance of a single downwind maintenance-only receptor. EPA has subsequently found in its promulgation of an ozone transport federal implementation plan ("FIP") that Minnesota was not linked to any downwind non-attainment or maintenance-only receptor when modeled for 2026.

Based on the best evidence available in 2018 when Minnesota submitted its SIP to EPA for approval (and on April 1, 2020 when EPA had a statutory obligation to approve or deny the Minnesota SIP), Minnesota was ***<u>not</u>*** linked to interference with attainment or maintenance in any downwind state. But, EPA did not timely act on the Minnesota SIP, and then it moved the goal posts. Based on new modeling and emission data EPA developed years later, (the "2016v2" modeling platform) EPA proposed to find that Minnesota was linked to two downwind maintenance-only receptors due to a modeled impact of less than 1 ppb at each receptor. In the

[1] As discussed on page 4 *infra*, EPA has divided the Good Neighbor obligation set out in Clean Air Act ("CAA") § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D), into two "prongs." The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2."

final SIP Disapproval, EPA again revised its emissions data and modeling (the "2016v3" modeling platform) and now finds that Minnesota is linked in 2023 to only a single maintenance-only monitor, at a maximum contribution of 0.85 ppb. Further, EPA has since released updated modeling results for 2026 that show that this same monitor will be in attainment without any material reduction of emissions from Minnesota. As a result, after five years of updates, EPA's modeling results support the same conclusion that Minnesota reached in 2018, namely that additional emissions reductions are not needed to prohibit emissions in Minnesota that will contribute significantly to nonattainment, or interfere with maintenance of, the 2015 8-hour ozone NAAQS in any downwind state. We ask that EPA grant this petition for reconsideration to do what it should have done in 2018—Approve the Minnesota SIP.

The approvability of Minnesota's original SIP submittal is corroborated by two additional pieces of information that were not available during the public comment period for the proposed SIP disapproval or prior to EPA's release of its 2016v3 modeling in 2023. First, EPA's 2016v3 emissions inventory materially overstates Minnesota's 2023 NOx emissions; for example, it incorrectly assumes over 2,800 tons of NOx from an electric generating facility that has been idled since 2019 and is projected to have zero emissions in 2023. By merely correcting the projected actual NOx emissions, Minnesota has already achieved more NOx reductions than EPA's FIP would require of Minnesota. This effectively confirms Minnesota's step 3[2] conclusion in its 2018 SIP that no additional permanent or enforceable measures were needed beyond those already implemented by the state.[3]

Second, as EPA has recognized, its CAMx modeling is subject to significant bias in areas of complex meteorology, including the water/land interface occurring at the sole maintenance monitor that EPA has linked to Minnesota emissions. While EPA released with the final SIP Disapproval a review of this localized bias risk for southern Lake Michigan, that review was materially flawed and does not address the significant over-prediction bias occurring on the precise days EPA selected for use in evaluating Minnesota's SIP. As a result, EPA's general conclusion that adjusting for bias will not affect the outcome of its SIP reviews, does not apply to its review of the Minnesota SIP. To the contrary, adjusting for material bias results in the sole maintenance-only monitor to which Minnesota was linked by EPA becoming an attainment monitor in 2023. In other words, eliminating high-bias days alone completely addresses EPA's objection to Minnesota's 2018 SIP and eliminates Minnesota at Step 1 of EPA's four-step analysis.

Reconsideration is appropriate to make the above corrections to the emissions inventory and to account for modeling bias. After incorporating this new material information into the SIP analysis, we believe that EPA will conclude as we have that Minnesota's original 2018 SIP determination that it is not having a downwind impact on attainment or maintenance that requires additional permanent and enforceable measures was correct and warrants approval of

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[2] *See* page 4 *infra* for the list of four steps in EPA's 4-step framework for evaluating Good Neighbor SIP submissions.

[3] *See* Minnesota's 110(a)(1) and 110(a)(2) "Infrastructure" State Implementation Plan requirements for the National Ambient Air Quality Standards for Ozone, Promulgated in 2015, EPA-R05-OAR-2022-0006-0005, at 12 (October 1, 2018) ("2018 SIP").

the Minnesota SIP. Reconsideration is also appropriate to address a significant procedural flaw in the finalization of the SIP Disapproval. Specifically, the SIP Disapproval relies on information that was not available to EPA, Minnesota, or any other interested parties until 2023, well past the period for Minnesota's SIP submission and EPA's statutory deadline to approve Minnesota's SIP. While EPA has an obligation to use the best available evidence in making its regulatory decisions, that obligation is not unbounded and cannot be used to circumvent the procedures set forth in the Clean Air Act. When Minnesota timely submitted a SIP that is approvable based on the information known at the time, EPA had an obligation to approve the SIP. The Act does not allow EPA unfettered discretion to delay approval until new information becomes available, and then move the goalposts. For States that have done their part to invest resources in developing a timely and approvable SIP, EPA has a statutory obligation to act. EPA may still consider new scientific data and modeling after the statutory deadline, but there is a separate administrative process available to EPA that respects the State's SIP process. Minnesota should have an approved SIP and EPA should be considering whether new information is sufficiently material to require a "SIP call" pursuant to CAA § 110(k)(5), 42 U.S.C. § 7410(k)(5), to give Minnesota the opportunity to revise its SIP given the new available information. Having chosen to use this new information to disapprove prong 2 of Minnesota's SIP instead, EPA deprived Petitioners, the State, and other interested parties of significant procedural protections and opportunities for public input that were required by the Clean Air Act. Granting reconsideration allows EPA the opportunity to cure the procedural flaw that its final action is based on material information that has not been subject to the notice and comment process.

Given that new information was made available after the close of the public comment period, but before the time for judicial review, that such information actually undermines EPA's basis for disapproving prong 2 of Minnesota's 2018 SIP in the SIP Disapproval, and reconsideration would address the harms caused by significant procedural defects in the SIP Disapproval, Petitioners respectfully request that EPA grant reconsideration for the purpose of reviewing this new information and approving prong 2 of Minnesota's 2018 SIP.

Further, since the disapproval of prong 2 of Minnesota's SIP, and the continued implementation of EPA's subsequently-issued FIP, will cause irreparable harm to Petitioners, we request that EPA grant a stay of the disapproval of prong 2 of Minnesota's SIP pending reconsideration and pending judicial review, which will also address the irreparable harm caused by EPA's FIP.

I. Background

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 ppb. This created a requirement under the CAA for states to submit revised SIPs to EPA by October 1, 2018.[4] SIPs were required to meet the applicable requirements of CAA § 110(a)(2), 42 U.S.C. § 7410(a)(2), including an obligation, sometimes referred to as a "Good Neighbor" obligation, that the SIPs:

[4] 42 U.S.C. § 7410(a)(1).

> (D) Contain adequate provisions—
>
> > (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—
> >
> > > (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, …

42 U.S.C. § 7410(a)(2)(D). The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2," of the Good Neighbor obligation.

While EPA has never promulgated regulations imposing more specific interstate transport requirements than what is contained in the statutory text, EPA has developed a 4-step framework that it stated the agency would use to evaluate a state's compliance with its Good Neighbor obligation. Namely:

(1) Identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (i.e., nonattainment and/or maintenance receptors);

(2) identify states that impact those air quality problems in other (i.e., downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis;

(3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and

(4) adopt permanent and enforceable measures needed to achieve those emissions reductions.[5]

Minnesota took a notably conservative approach in its SIP. First, in EPA's Transport Memo, EPA recognized that its four-step framework was not binding, and offered that states "have flexibility to follow this framework or develop alternative frameworks."[6] Despite this flexibility, Minnesota adopted EPA's framework for its SIP.[7] Second, EPA made clear, in the

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[5] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf at 2-3 (March 27, 2018) ("Transport Memo").
[6] *Id.*
[7] 2018 SIP at 5.

Transport Memo and in a separate memorandum published later that year, that states did not need to adopt EPA's suggested 1% threshold for determining significant contributions and interference with maintenance at step 2.[8] Here too, Minnesota did not exercise this flexibility, and chose instead to use EPA's preferred approach.[9] Third, EPA guidance offered states flexibility regarding how to determine which downwind monitors should be considered maintenance receptors.[10] Again, Minnesota followed EPA's suggested approach.[11] In other words, while Minnesota was not required to, it followed EPA's own framework and did not rely on additional flexibilities to demonstrate that it had satisfied its Good Neighbor obligations.[12]

Minnesota also used the best information available at the time to determine its Good Neighbor obligations. Specifically, Minnesota used EPA's own modeling and modeling developed by the Lake Michigan Air Directors Consortium ("LADCO") to identify monitoring sites projected to have problems attaining or maintaining the 2015 ozone NAAQS in 2023.[13] It then projected the state's own contributions to those nonattainment and maintenance monitors using both sets of results.[14] Both EPA's and LADCO's modeling showed that Minnesota would contribute less than 1 percent of the NAAQS to all downwind receptors, with a highest receptor contribution from either model of 0.45 ppb.[15] Thus, following EPA's 4-factor framework, and using EPA's own modeling and proposed threshold, Minnesota demonstrated that it was not contributing significantly to, or interfering with maintenance of, the 2015 ozone NAAQS in any downwind state.

This alone would have been sufficient to satisfy Minnesota's Good Neighbor obligation. Minnesota also, however, included in its SIP submission a "step 3" analysis demonstrating that Minnesota emissions of ozone precursors had been reduced from 2002 through 2015 and would be further reduced by emission limitations and reductions required by other programs.[16] Under this step 3 analysis, Minnesota demonstrated that, even if the state were having more than an insignificant impact on downwind receptors (as EPA now asserts), Minnesota's existing glidepath of emissions reductions still supported a finding that no further emission control measures would

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[8] Transport Memo at A-2; Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards (Aug. 31 2018) ("Threshold Memo")

[9] 2018 SIP at 6.

[10] Transport Memo at A-2; Consideration for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, https://www.epa.gov/sites/default/files/2018-10/documents/maintenance_receptors_flexibility_memo.pdf at 3 (October 19, 2018) ("Maintenance Memo")

[11] 2018 SIP at 5.

[12] Minnesota, of course, could have taken a different approach, and might have used some of these flexibilities, had EPA indicated during the statutory review period that it was considering disapproving prong 2 of Minnesota's SIP.

[13] 2018 SIP at 5-9.

[14] *Id.*

[15] *Id.* at 8-9.

[16] *Id.* at 9-12; *see also id.* at 13.

be needed to address this impact. EPA did not meet its obligation to approve or deny Minnesota's complete and approvable SIP within 12 months of submittal.

Approximately three years after EPA's deadline to approve the Minnesota SIP, EPA proposed to disapprove Minnesota's SIP on February 22, 2022, along with SIPs from 18 other states.[17] EPA did not identify a technical error in Minnesota's submission or any inconsistency with the Good Neighbor requirements, or even EPA's own framework. In fact, EPA recognized that "the modeling the MPCA used relied on the most recently available EPA modeling at the time the state submitted its SIP submittal."[18] Nonetheless, EPA proposed to reject Minnesota's SIP because EPA chose to rely "on the Agency's most recently available modeling, which uses a more recent base year and more up-to-date emissions inventories, to identify upwind contributions and 'linkages' to downwind air quality problems in 2023 using a threshold of 1 percent of the NAAQS." *Id.* Based on this data, EPA proposed to reject Minnesota's conclusion that it was not linked to a downwind receptor, and to find instead that Minnesota was linked to two maintenance monitors in Cook County, Illinois, one with a maximum contribution of 0.97 ppb and the other 0.79 ppb.[19]

On February 13, 2023, EPA published the SIP Disapproval. In its final rule, EPA approved Minnesota's SIP as to "prong 1" but disapproved Minnesota's SIP as to "prong 2."[20] Rather than use the emissions data and modeling available to Minnesota in 2018, or even emissions data and modeling available at the time of the proposed SIP disapproval, EPA made a number of additional updates to its emissions inventories and model design to construct a new 2016v3 emissions platform, which it used to generate new air quality modeling without seeking public comment to allow affected party input to help the agency assess the accuracy of the new information utilized in the modeling.[21] Minnesota was now no longer linked to two downwind receptors. It was now linked to only a single maintenance-only receptor, at a maximum contribution of 0.85 ppb for 2023.[22]

While EPA also conducted updated modeling for 2026, it did not release this information in the docket for the SIP Disapproval, stating it was "not applicable" and "not used in this final action."[23] EPA subsequently made these results available, however, on EPA's website for its Federal Implementation Plan ("FIP") for 23 states, including Minnesota.[24] Based on EPA's modeling for 2026, Minnesota is not linked to any downwind nonattainment or maintenance-only receptor. In fact, based on EPA's modeling, the sole maintenance-only receptor Minnesota was linked to in 2023 is in attainment by 2026, and Minnesota's largest contribution to any

[17] Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838, 9868 (February 22, 2022) ("Proposed Rule").
[18] Proposed Rule at 9867.
[19] *Id.* at 9868.
[20] *See S*IP Disapproval at 9357.
[21] *See id.* at 9339.
[22] *Id.* at 9357.
[23] *Id.* at 9344, n.49.
[24] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs

downwind nonattainment or maintenance-only receptor is just 0.32 ppb.[25] Notably, this modeling assumed no installation of additional pollution controls in Minnesota. The only emissions reductions included from Good Neighbor obligations were an annual reduction of 139 tons NOx from emissions control optimization at EGUs.[26]

II. Grounds for Reconsideration of the SIP Disapproval

Reconsideration is justified under either CAA § 307(d)(7)(B)[27] or Administrative Procedure Act ("APA") § 553(e) (5 U.S.C. § 553(e)).[28] Under CAA § 307(d), reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[29] Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020). Under the APA, EPA has "broad discretion to reconsider" its SIP Disapproval "at any time" Under the APA. *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).[30]

Three grounds support reconsideration under either standard. First, EPA's 2016v3 modeling did not have the benefit of Petitioners' or other public comments. As a result, it contains a significant overestimation of 2023 emissions for Minnesota. Second, EPA's 2016v3 modeling of the sole monitor supporting a potential linkage between Minnesota and Illinois is subject to significant bias which, if corrected for, results in the same receptor modeling attainment in 2023. Third, EPA's rejection of prong 2 of Minnesota's SIP was procedurally

[25] *See* Federal "Good Neighbor Plan" for the 2016 Ozone National Ambient Air Quality Standards, https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf, at 198 (pre-publication version).
[26] Compare *Id.* at 290, Table V.C.1-1; 291, Table V.C.1-2; and 452, Table VI.B.4.c-1.
[27] 42 U.S.C. § 76076(d)(7)(B).
[28] SIP disapprovals are not automatically subject to the exhaustion requirements of Clean Air Act § 307(d). 42 U.S.C. § 7607(d). This subsection lists 22 categories of agency action subject to the exhaustion requirement. SIP approval and disapproval, separate from issuance of a FIP, as occurred in the SIP Disapproval, is not addressed by any of these 22 categories.
[29] 42 U.S.C. § 7607(d)(7)(B).
[30] *See also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.")

improper because it was based entirely on results EPA obtained in 2023, well past the statutory deadline for Minnesota's SIP submission and EPA's decision approving or disapproving it.

A. Errors in EPA's New Emissions Data and Modeling, Which Were Not Subject to Notice and Comment, Support Reconsideration to Ensure EPA's Decision on Minnesota's SIP is Based on Valid and Accurate Information.

EPA "made a number of updates to [its] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval uses "this updated modeling to inform [EPA's] final action on [state] SIP submissions," including Minnesota's. *Id.*

The new emissions inventory and modeling platform are of central relevance to EPA's rule. EPA identifies the 2016v3 platform as designed "to inform [the agency's] final action on these SIP submissions." SIP Disapproval at 9339. For Minnesota, the 2016v3 modeling results are the sole record citation EPA provides for its finding that prong 2 of Minnesota's SIP was "ultimately inadequate." *Id.* at 9357.

While there have been errors in each of EPA's inventories at each stage of the regulatory process, these new errors in the emissions inventory arose only with the publication of the final SIP Disapproval. Under both the APA and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment on the evidence on which EPA intends to rely for its final rules.[31] EPA's emissions inventory and modeling design changes were not made publicly available until EPA published the SIP Disapproval and several supporting documents on the same day. As a result, the public, including Petitioners, did not have the opportunity to review EPA's data and correct errors before then.

In the limited time Petitioners have had to review the 2016v3 data, we have identified significant errors in EPA's estimate of NOx emissions for 2023. As an example, EPA added 2,822 tons of NOx for Northshore Mining Co. – Silver Bay power. These boilers have been idled since October 2019 and are expected to have zero emissions in 2023. EPA itself recognizes that zero emissions are expected at this facility in both its OTP Policy Analysis, Appendix A and in its Unit-Level Allocations and Underlying Data for the Final Rule (both available at https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs). Yet EPA made no adjustment to its 2016v3 data, resulting in a significant overestimate of 2023 emissions from Minnesota used by EPA to justify disapproval of the Minnesota SIP. If EPA defends including 2,822 tons of NOx emissions for Silver Bay Power in the baseline actual emissions used to model Minnesota's downwind impact in 2023, then Minnesota's state allowance budget should be

[31] *See Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 540 (D.C. Cir. 1983) (adding evidence on which EPA relies after the close of the comment period would be "highly improper"); *see also Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981) ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations).

increased to reflect those emissions and Silver Bay Power should receive proportional allowance allocations for the 2023 CSAPR ozone season trading program and beyond. To do otherwise would be internally inconsistent, which is an indication of arbitrary rulemaking.

For Minnesota, EPA's most recent modeling identified a single impacted maintenance monitor in 2023, at which Minnesota's maximum impact was 0.85 ppb. EPA's latest modeling projects this same receptor will be in attainment by 2026 with no reductions from Minnesota other than already "on the books" rules and regulations.[32] In other words, EPA's 2026 modeling confirms Minnesota's 2018 SIP conclusion that "the limits and controls that Minnesota already has in place across the state are sufficient to make it reasonably certain that Minnesota will not significantly contribute to nonattainment or interfere with maintenance in any other state" and that "no further controls or emissions limits are required to fulfill [Minnesota's] responsibilities under the interstate transport provisions for the 2015 ozone NAAQS under prongs 1 and 2 of Section 110(a)(2)(D)(i)(I)."[33]

Given the above considerations, EPA should grant reconsideration to reassess Minnesota's 2018 SIP in light of its own modeling showing that no further emission reductions are needed for Minnesota to satisfy its prong 2 good neighbor obligations.

B. The Sole Monitor that Links Minnesota Models in Attainment for 2023 When Bias is Removed.

Minnesota's only link to a downwind state receptor is the Alsip/Village Garage monitor located in Cook County, Illinois (170310001). This monitor is located near the southern shore of Lake Michigan at a land-water interface with complex meteorology**.** This monitor is currently measuring attainment with the 2015 ozone NAAQS using the 2021 4th highest daily maximum value (68 ppb). However, EPA's air quality modeling predicts that this monitor is at risk of violating the ozone NAAQS and, therefore, designates it as a maintenance-only receptor. Upwind states that interfere with this monitor's maintenance of the ozone NAAQS are linked through prong 2**.** However, if a corrected model predicts the monitor's maximum 2023 design value will attain the 2015 ozone NAAQS, this monitor falls out of the analysis at Step 1 and, since no other monitor links to Minnesota, EPA will have no basis for disapproval of prong 2 of Minnesota's SIP.

In the attached analysis, Alpine Geophysics demonstrates that the Cook County monitor models attainment for the 2015 ozone NAAQS in 2023. Alpine Geophysics evaluated this Cook County monitor and concluded that its location at a land-water interface at the southern shore of Lake Michigan presents highly complex meteorological conditions and ozone photochemistry that complicate the air quality model's ability to replicate ozone concentrations reliably. Of note,

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[32] *See* Air Quality Modeling Final Rule Technical Support Document, https://www.epa.gov/system/files/documents/2023-03/AQ%20Modeling%20Final%20Rule%20TSD.pdf at 17, Table 3-5 (showing Monitor 170310001 no longer listed as a monitor-only receptor in the 2026 base case).
[33] 2018 SIP at 13.

EPA's application of a 12 km grid resolution in such areas is contrary to EPA's own guidance.[34] Alpine Geophysics reviewed EPA's day-specific model performance for the estimation of ozone concentrations on days EPA used to calculate future year design values and found significant bias in the majority of modeled day values used to designate this monitor site as a maintenance-only receptor. When Alpine Geophysics adjusted for this bias by using daily concentration values within acceptable normalized bias boundaries (+/- 15%), the updated list of top ten days used to designate the Cook County monitor resulted in both its average and maximum design values to be calculated in attainment with the 2015 ozone NAAQS.

When one attaining monitor modeled as a maintenance-only receptor is the sole basis for a state's linkage, a refined level of analysis is particularly important when predicting future design values and significant contribution**.** When that monitor is in a highly complex land-water interface area, it is not surprising for refined analysis to show significant bias**.** In its FIP rulemaking, EPA looked at this impact, but evaluated only one of ten Cook County monitors.[35] In doing so, EPA evaluated the only monitor out of the ten where EPA's performance-based recalculation resulted in a higher design value. As a result, EPA's sensitivity analysis materially understates the significance of the bias impact on the Alsip/Village Garage monitor and this issue remains central to EPA's evaluation of Minnesota's 2018 SIP.

Petitioners also had no ability to evaluate the bias in EPA's 2016v3 modeling of the Alsip/Village Garage monitor prior to EPA's release of its model and supporting data. As a result, this information arose after the close of the public comment period and within the time for judicial review.

Since Petitioners have identified significant bias in the sole receptor on which EPA relies to find a link to Minnesota and reject Minnesota's 2018 SIP, reconsideration is appropriate to evaluate the new information and analysis provided. When reasonably adjusting for the bias in EPA's 2016v3 modeling of that receptor, EPA will be in a position to confirm that Minnesota accurately concluded in 2018 that there are no "potential nonattainment or maintenance receptors significantly impacted by ozone transport from Minnesota in 2023" and that "[t]herefore, Minnesota does not have a responsibility to identify or implement any further controls or emissions limits to reduce downwind ozone contribution."[36]

C. Minnesota's SIP Should Have Been Approved Based on the Data Available at the Statutory Deadlines for Submission or Review.

The Clean Air Act sets out a detailed process for EPA's review of SIPs in CAA § 110(k). 42 U.S.C. § 7410(k). For timely submitted plans that have been deemed complete, like Minnesota's,

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[34] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze, https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf (Nov. 29, 2018).

[35] *See* Federal "Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Response to Public Comments on Proposed Rule, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf at 196.

[36] 2018 SIP at 9.

EPA has twelve months to act on a plan submission. 42 U.S.C. § 7410(k)(2). For a plan that meets the requirements of the Clean Air Act, "the Administrator shall approve such submittal as a whole." *Id.* at (k)(3). If a portion of the plan revision meets all the applicable requirements, EPA "may approve the plan revision in part and disapprove the plan revision in part" but "[t]he plan revision shall not be treated as meeting the requirements of [the Clean Air Act] until the Administrator approves the entire plan revision as complying with the applicable requirements of [the Clean Air Act]." *Id.* In other words, while EPA has discretion to partially approve a SIP submittal that does not meet all requirements of the Clean Air Act, if a submission meets all requirements of the Act, EPA does not have discretion. It must approve the SIP. *See also Utah Physicians for a Healthy Env't v. Kennecott Utah Copper, LLC*, 191 F. Supp. 3d 1287, 1290 (D. Utah 2016) ("If a SIP satisfies the applicable requirements, EPA must approve it.").

In 2018, Minnesota submitted a timely and approvable SIP. As EPA acknowledges in the SIP Disapproval, Minnesota "was not projected to be linked to any receptor in 2023 in the EPA's 2011-based modeling."[37] Petitioners retained Alpine Geophysics to reanalyze Minnesota's SIP submission considering the best evidence available both at the time of Minnesota's SIP submission and at the time of EPA's statutory obligation to approve or disapprove Minnesota's SIP. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota's SIP submission: (1) had no material errors; (2) relied on the best science (including emissions data and modeling) available at the time; (3) fully complied with the CAA's requirements and EPA's guidance; and (4) would have been approved had EPA not incorporated information unavailable during the statutory review period. As a result, pursuant to 42 U.S.C. § 7410(k)(2) and (k)(3), by April 1, 2020, EPA had a non-discretionary duty to approve Minnesota's SIP. While EPA missed its statutory deadline, this did not relieve EPA of its duty to approve Minnesota's SIP.

While EPA now finds that "in light of more recent air quality analysis," Minnesota is linked to a single maintenance monitor in Illinois, this is based on information that did not exist at the time of Minnesota's SIP submission nor when EPA had a statutory obligation to approve the SIP. This was also not EPA's first use of untimely information to assess Minnesota's SIP. In 2022, EPA proposed to disapprove Minnesota's SIP "[s]ince new modeling ha[d] been performed by EPA with updated emission data," that EPA proposed "to primarily rely on … to identify nonattainment and maintenance receptors in 2023." Proposed Rule at 9867. As EPA acknowledged at the time, this was "a different method for projecting emissions" than what had been available to Minnesota for it to develop its SIP submittal. *Id.* EPA's repeated changes in emissions inventory and modeling platform after the deadline for SIP submissions and after Minnesota's SIP was deemed complete by EPA effectively moved the goalpost for Minnesota's SIP, undercutting the State of Minnesota's ability to identify the requirements EPA would apply to determine an approvable SIP.

The impact was significant. Minnesota's modeled impact went from contributing "below 1 percent of the NAAQS to receptors in 2023" to contributing "greater than 1 percent of the standards to two maintenance-only receptors in Illinois"[38] in the 2022 proposed SIP Disapproval

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[37] SIP Disapproval at 9357.
[38] *Id.* at 9867-68.

to now being linked to one maintenance-only receptor in the 2023 SIP Disapproval (assuming no further adjustment for bias or data inaccuracies)). Notably, even using EPA's new data and modeling, Minnesota would still have had no linkage to a downwind maintenance receptor if EPA had not also moved the maximum threshold it indicated it would consider acceptable from 1 ppb to 1% (0.70 ppb).[39] As the D.C. Circuit has held, it is arbitrary and capricious to give states a "constantly moving target," *New York v. EPA*, 964 F.3d 1214, 1224 (D.C. Cir. 2020), let alone two. The language and structure of the Clean Air Act clearly give Minnesota and Petitioners the right to address this new data in the first instance in a SIP amendment, and not in a challenge to a SIP disapproval, as EPA now requires.

Notably, if EPA had followed the CAA procedures, it could have appropriately considered the new information it has developed since 2020, including the 2016v3 modeling it has introduced with the 2023 SIP Disapproval. But EPA cannot rely on its almost three year delay to circumvent the process and procedural protections set forth in the Clean Air Act. Rather, EPA was required to act on the SIP Minnesota submitted. If, after approval, EPA finds that a timely, complete and approved SIP nonetheless is "substantially inadequate … to mitigate adequately the interstate pollutant transport" or otherwise comply with the requirements of the Clean Air Act, "the Administrator shall require the State to revise the plan as necessary to correct such inadequacies." *Id.* at (k)(5). EPA also cannot simply disapprove the state's plan pending a new state submission that incorporated EPA's newly developed information, as the SIP Disapproval effectively does. In the event EPA finds a SIP Call is justified, EPA must first "notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions." *Id.* Further, "[s]uch findings and notice shall be public." *Id.* These procedural protections are an important component of the cooperative federalism embodied in the Clean Air Act. As courts have held, "[t]he Clean Air Act is an experiment in federalism, and the EPA may not run roughshod over the procedural prerogatives that the Act has reserved to the states, especially when … the agency is overriding state policy. *Bethlehem Steel Corp. v. Gorsuch*, 742 F.2d 1028, 1036–37 (7th Cir. 1984).

Multiple commenters, including the Minnesota Pollution Control Agency, have raised similar concerns arising from EPA's initial proposal to use 2016v2 modeling to disapprove state SIPs.[40] EPA has attempted to respond to those comments in the RTC, but in doing so, has not addressed the fundamental issue that EPA cannot disapprove a SIP that is approvable based on the information existing at the time that submittals are due, or even at the time EPA's SIP review was statutorily due, and cannot circumvent Minnesota's right to address new data in a SIP amendment, before EPA uses it to disapprove an otherwise approvable SIP. 42 U.S.C. §§ 7410(k)(3) and (5).

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[39] Minnesota did not rely on the 1 ppb threshold for its SIP submission, but as EPA acknowledged, "[t]he 2018 modeling indicated the state was not projected to contribute above one 1 percent of the NAAQS to a projected downwind nonattainment or maintenance receptor. Therefore, the state may not have considered analyzing the reasonableness and appropriateness of a 1 ppb threshold at Step 2 of the 4-step Step interstate transport framework per the August 2018 memorandum." Proposed Rule at 9867.

[40] *See* RTC at 42-59.

EPA asserts in the SIP Disapproval that its use of new modeling and data did not move the goal post for states because EPA "did not evaluate states' SIP submissions based solely on the 2016v2 emissions platform (or the 2016v3 platform…)" but rather "evaluated the SIP submissions based on the merits of the arguments put forward in each SIP submission." SIP Disapproval at 9366. For Minnesota, however, EPA cites no basis or analysis for its SIP Disapproval other than the 2016v3 modeling results. Having relied on no other information to disapprove Minnesota's SIP, EPA cannot simply assert it had an additional basis with no additional substantiation. As the D.C. Circuit has noted, EPA cannot support its decision on only a "Delphic explanation of [Minnesota's] purported failure to carry its burden of proof." *New York*, 964 F.3d at 1224.

EPA also maintains that data and modeling it developed for the Proposed Rule in 2022, and now additional data and modeling it developed for the SIP Disapproval in 2023, supports a finding that Minnesota's SIP submission is "ultimately inadequate." SIP Disapproval at 9357. But even if this were the case, it does not give EPA a right to disapprove Minnesota's 2018 SIP. For data arising after EPA's statutory deadline to approve Minnesota's SIP, EPA could no longer rely on its obligation to use the "best information available." SIP Disapproval at 9366. Interpreting the Clean Air Act otherwise would not do justice to the cooperative federalism framework Congress established in CAA § 110, and would deprive states of important procedural protections allowing them to control and direct in the first instance, the implementation of the NAAQS within their borders.

The SIP Disapproval misapplies the D.C. Circuit's reasoning in *Wisconsin*, 903 F.3d at 322, when it asserts the SIP submission deadline is "'procedural'" and that to limit EPA's decision to information available at the time of the SIP submission or EPA's statutory review deadline would elevate it above requirements "'central to the regulatory scheme.'" SIP Disapproval at 9366 (quoting *Wisconsin*, 903 F.3d at 322. Neither *Wisconsin*, nor the case on which it relies, *Sierra Club v. EPA*, 294 F.3d 155 (D.C. Cir. 2002), addressed the issue presented here. In *Wisconsin*, the court was responding to an argument that EPA should have selected 2011 as its analytic year even though that year had already passed. In *Sierra Club*, the court was responding to a contention that EPA's ability to extend a SIP submittal deadline should support its authority to extend attainment deadlines. Here, EPA argues for an exception that would swallow the rule. If EPA could simply withhold ruling on a SIP until the State's information had become stale, and then disapprove the SIP and issue a FIP based on the "best available information," the cooperative federalism structure of the NAAQS would be an empty shell.

This is also not a situation like that which arose in *EME Homer City Generation, L.P. v. EPA,* 795 F.3d 118 (D.C. Cir. 2015). There, EPA had approved state SIPs in reliance on the Clean Air Interstate Rule ("CAIR"), which was subsequently found to have "more than several fatal flaws" by the D.C. Circuit. *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C.Cir.2008) (*per curiam*). In addressing whether this ruling allowed EPA to "correct" its earlier SIP approvals under 42 U.S.C. § 7410(k)(6), the D.C. Circuit found EPA could do so, but only due to the unique circumstances of that case. *EME Homer City Generation*, 795 F.3d at 135 n.12 ("Our conclusion on Subsection 7410(k)(6) is limited to the unusual circumstances here, in which a federal court says that EPA lacked statutory authority at the time to approve a SIP."). Notably, the D.C. Circuit

did not decide whether EPA could rely on Clean Air Act §110(k)(6) to disapprove an approved SIP "in any other circumstances," and stated that its holding in particular "should not be read to diminish the scope or force of Subsection 7410(k)(5), which provides that whenever 'the Administrator finds that the applicable implementation plan for any area is substantially inadequate ... the Administrator shall require the State to revise the plan as necessary to correct such inadequacies.'" *Id.* (quoting 42 U.S.C. § 7410(k)(5)).

While in *EME Homer,* EPA had already approved several state SIPs, and in this rulemaking EPA has not yet approved Minnesota's SIP, this is a distinction without a difference. Minnesota submitted its SIP on October 1, 2018. It was deemed complete April 1, 2019.[41] EPA's period for review therefore ended April 1, 2020. As described in the Proposed Rule, Minnesota's SIP submission complied with the Clean Air Act and EPA's guidance for developing an interstate transport SIP for the 2015 ozone NAAQS. 87 Fed. Reg. at 9848-49. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota timely submitted an approvable SIP. By April 1, 2020, EPA had a statutory duty to approve Minnesota's SIP.

EPA's reliance on its 2016v3 modeling platform (which was not available to the public or interested parties) to reject the conclusions Minnesota reached based on the information that was available to all parties at the time is clearly of central relevance. Had EPA acted by its statutory deadline, Minnesota would have an approved SIP today. Further, while Petitioners have previously commented on the approvability of Minnesota's SIP, the basis for EPA's partial SIP Disapproval for Minnesota, including its decision to rely on its newer 2016v3 modeling platform, was not made public until the final rule. These grounds therefore arose after the close of the public comment period but before the time for judicial review. Reconsideration is therefore appropriate to address this procedural anomaly for Minnesota.

On reconsideration EPA should approve Minnesota's 2018 SIP based on the information that was available to EPA for its statutory review. The agency may then reassess whether, based on the information available today, including the above data and bias corrections, Minnesota's SIP remains sufficient to comply with prong 2 of the state's Good Neighbor obligations. For the reasons explained herein, EPA should find that the 2018 SIP was and is adequate to comply with prong 2.

III. Grounds for Stay of the SIP Disapproval

EPA has authority to stay the SIP Disapproval both pending reconsideration and pending judicial review. First, if the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration can be granted for three months. Second, EPA has authority under the APA to stay the SIP Disapproval pending judicial review.

[41] *See* https://www3.epa.gov/airquality/urbanair/sipstatus/reports/mn_infrabypoll.html

A. A Stay Under CAA § 307(d)(7) is Appropriate.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). If the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration is justified here.

EPA issued a final rule based primarily on emissions data and modeling that it did not make publicly available before issuance of the final rule. Even upon publication, EPA's release of data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the data and checking its accuracy has taken several weeks. It would take many more weeks to rerun EPA's modeling to confirm that the results support reversal of EPA's disapproval of prong 2 of Minnesota's SIP. It will likely take a similar amount of time to evaluate the evidence of bias Petitioners are submitting to confirm that it too, supports approval of Minnesota's SIP.

A stay will also not unduly impact downwind states. Minnesota is not modeled to interfere with attainment for any downwind state. Under EPA's most recent modeling, Minnesota is linked only to a single maintenance-only receptor, the most recent monitored design value of the monitor at this location was in attainment, and EPA's modeling for 2026 shows the receptor will model attainment as well with only minimal reductions from Minnesota. As EPA has itself emphasized, the SIP Disapproval does not require any action from the states.[42]

While a stay of the effective date of the SIP Disapproval for Minnesota would also prevent EPA from applying its FIP to Minnesota at the start of the upcoming ozone trading season, which is scheduled to start May 1, 2023, this is not likely to be relevant. In a recent filing, EPA has stated that the FIP is not likely to be effective until "late June to early July."[43] If EPA timely takes action on this reconsideration, this is well within the time EPA would need to conduct reconsideration. Further, while EPA has interpreted the CAA to require it "to address good neighbor obligations as expeditiously as practicable and no later than the next attainment date," RTC at 445, granting a stay of Minnesota's SIP denial pending reconsideration will not interfere with that goal. Minnesota is modeled to impact only a single maintenance-only monitor. As the D.C. Circuit has recognized, this 'may be a valid reason" to postpone addressing emission reductions until even after the next attainment date. *North Carolina v. EPA*, 531 F.3d 896, 912 (D.C. Cir. 2008). A reasonable stay to address reconsideration falls well within EPA's discretion.

B. EPA Should Stay the Effective Date of the SIP Disapproval Pending Judicial Review.

EPA can consider a stay of the entire SIP Disapproval for all affected states. Under the APA, EPA may stay the effective date of the SIP Disapproval pending judicial review when "justice

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[42] *See, e.g.*, 2015 Ozone NAAQS Interstate Transport SIP Disapproval – Response to Comments ("RTC") at 466.
[43] Respondents' Consolidated Response in Opposition to the Motions for Stay of the Final Rule, *Texas v. EPA*, Case No. 23-60069, Doc. 109, at 12 (5th Cir. Filed March 27, 2023).

so requires." 5 U.S.C. § 705. Several Petitioners are filing a petition for judicial review of EPA's partial disapproval of Minnesota's SIP contemporaneously with this petition for reconsideration and stay. Multiple other petitions have already been filed for judicial review, including petitions by Arkansas, Kentucky, Oklahoma, Texas, Utah, and Wyoming. More are likely. These cases are already spread across four circuits, and additional litigation may expand the number of courts further.

The effective date of the SIP Disapproval is March 15, 2023. This effective date is significant for both legal and practical reasons. Legally, it will force EPA to promulgate a FIP within two years (though in this case EPA has already finalized its FIP). 42 U.S.C. § 7410(c)(1). States will also be required to prepare SIP revisions if they are interested in addressing the errors in EPA's analysis. Further, the significant legal flaws in EPA's SIP Disapproval discussed above, coupled with the technical and legal concerns it raises, make it likely that judicial review will result in a remand if not vacatur of the current SIP Disapproval. As a result, to avoid the unnecessary expenditure of EPA resources on a FIP, state resources on SIP revisions, and the resources of the public and regulatory industries in addressing a FIP that is likely to not be required, justice requires that the SIP Disapproval be stayed pending judicial review.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors indicate support for EPA in granting a stay of the SIP Disapproval. Under this standard, the considerations for a stay are:

(1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits;

(2) whether the applicant will be irreparably injured absent a stay;

(3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and

(4) where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

1. Petitioners Have Made a Strong Showing They Are Likely to Succeed on the Merits

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id. (quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the SIP Disapproval has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's partial SIP Disapproval for Minnesota was based on an incorrect set of emissions data and biased modeling results that, when adjusted, support Minnesota's original conclusion that the state is not linked to downwind nonattainment or interference with maintenance and, even if linked, does not need to impose additional emission reductions to satisfy its Good Neighbor obligations. Procedurally, EPA did not follow the process required by the Clean Air Act for reviewing and approving Minnesota's SIP. In doing so, EPA deprived the State and Petitioners of the ability to address EPA's concerns in a SIP Call process.

Other flaws in the SIP Disapproval also strongly support a showing of likely success on the merits in a judicial challenge. In particular, we call to the agency's attention: (a) EPA's impermissible reliance on new data to disapprove prong 2 of Minnesota's SIP without providing adequate notice and an opportunity for public comment; and (b) the SIP Disapproval's subversion of the well-established and vital cooperative federalism underlying the entire Clean Air Act and in particular, the NAAQS.

a. *EPA Cannot Base its SIP Disapproval on Information that was Not Subject to Adequate Notice and Public Comment*

Under both the Administrative Procedure Act ("APA") and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id.* at 540. Adding evidence on which EPA relies after the close of the comment period is "highly improper." *Id.* at 540; *see also Sierra Club*, 657 F.2d at 400 ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."). Even reconsideration cannot cure an inadequate opportunity for notice and comment. *U. S. Steel v. EPA*, 595 F.2d 207, 214 (5th Cir. 1979) ("Permitting the submission of views after the effective date is no substitute for the right of interested persons to make their views known to the agency in time to influence the rulemaking process in a meaningful way.") (Internal quotations omitted).

In the SIP Disapproval, EPA "made a number of updates to [it's] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval used "this updated modeling to inform [EPA's] final action on [Minnesota's] SIP submissions." *Id.* The details of these emissions inventory and modeling design changes were first described to the public in the SIP Disapproval and associated documents made publicly available the same day.[44] Even then, EPA did not make public its 2026 modeling results, reserving these for finalization of the FIP several weeks later.

[44] Even then, the supporting data and modeling platform were not made electronically available and needed to be requested by the public, which added several more weeks to gain access.

This data and modeling were clearly of central importance to EPA's disapproval of prong 2 of Minnesota's SIP. In fact, they are the sole basis for EPA's disapproval. *See* SIP disapproval at 9357 (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"); *see also id*. (disapproving prong 2 of Minnesota's SIP because "[i]n the 2016v3 modeling, Minnesota is projected to be linked above 1 percent of the NAAQS to one maintenance-only receptor"). As a result, EPA was required to provide the public advance notice of its new data and an opportunity for meaningful public comment.

EPA's publication of its revised emissions inventory and modeling the day of the SIP Disapproval did not satisfy this requirement. In *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982), the D.C. Circuit found EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations. Here, EPA did not make its new emissions data and modeling publicly available until the *day* it published its final SIP Disapproval.

It is not enough to say that Petitioners had the opportunity to comment on EPA's previous version of the emissions data and modeling, or that EPA's latest data simply "incorporates comments generated during the public comment period." SIP Disapproval at 9366. As the D.C. Circuit stated in *Chesapeake*, 952 F.3d at 320, it would be an "unreasonable burden on commenters not only to identify errors in a proposed rule but also to contemplate why every theoretical course of correction the agency might pursue would be inappropriate or incorrect." The new data and modeling on which EPA relies for the SIP Disapproval differs significantly from that which was in the public record. Based on EPA's own summary of the data, Minnesota's largest contribution to a downwind maintenance receptor changed from 0.97 ppb to 0.85 ppb based on EPA's changes. *Compare* Proposed Rule at 9868 *with* SIP Disapproval at 9354. Since EPA's own adopted significant contribution threshold in the SIP Disapproval is 0.7 ppb, a change of 0.12 ppb is clearly significant.[45]

Under both the CAA and the APA, EPA was required to provide notice and an opportunity for public comment on its 2016v3 data. There is no question that EPA provided no notice or opportunity for comment. As a result, there is a high likelihood that Petitioners would be likely to prevail on the merits of a judicial challenge. This strongly supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

b. *EPA Undermined State Primacy by Disapproving Minnesota's SIP Despite its Adherence to the Requirements of the Clean Air Act.*

As EPA acknowledges, "[t]he CAA establishes a framework for state-Federal partnership to implement the NAAQS based on 'cooperative federalism.'" SIP Disapproval at 9367. Under this model, "the Federal Government establishes broad standards or goals, states are given the

[45] EPA's 2016v3 modeling did not just result in significant changes to EPA's assessment of Minnesota's potential impact on downwind states. Six states (Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming) had their status as linked states change entirely. *See* Air Quality Modeling Technical Support Document 2015 Ozone NAAQS SIP Disapproval Final Action, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0663-0017 at 24.

opportunity to determine how they wish to achieve those goals, and if states choose not to or fail to adequately implement programs to achieve those goals, a Federal agency is empowered to directly regulate to achieve the necessary ends." *Id.* Thus, "states have the obligation and opportunity in the first instance to develop an implementation plan to achieve the NAAQS under CAA section 110" and "EPA will approve SIP submissions under CAA section 110 that fully satisfy the requirements of the CAA." *Id.* As the Supreme Court has held: "[e]ach State is given wide discretion in formulating its plan, and the Act provides that the Administrator 'shall approve' the proposed plan if it has been adopted after public notice and hearing and if it meets [the CAA's] criteria." *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976) (*quoting* 42 U.S.C. § 7410(a)(2)).

EPA departed from this framework when it proposed a SIP disapproval based, not on any inaccuracy in Minnesota's evaluation of the data, but on EPA's preference for a different modeling platform and emissions inventory. EPA does not have the authority to condition SIP approval on the state's adoption of EPA's preferred approach, or to supplant Minnesota' interpretation of how best to achieve the goals of the CAA, as long as Minnesota complies with the requirements of the CAA.

EPA's position is predicated on an incorrect summary of its role in the SIP review process and the relevant case law. First, EPA's role is not "secondary" only in that "it occurs second in time." RTC at 425 (internal quotations omitted). EPA relies on *EPA v. EME Homer City Generation*, LP, 572 U.S. 489 (2014) for this proposition, but the case does not support EPA's position. It must be remembered that *EME Homer* involved EPA's authority to promulgate a FIP after EPA had already disapproved SIPs.[46] As a result, the Court did not address EPA's statutory duty to approve a timely and complete SIP submission, which is the issue here. The Court's "interpretations of CAA section 110(a)(2)(D)(i)(I)" on which EPA relies must be read in this light. RTC at 426. The Court upheld interpretive choices EPA made when issuing a FIP. The Court did not say EPA could delay approval until new information became available that supported its disapproval of the SIP.

Second, EPA is wrong to imply that *EME Homer* undermines the long line of cases setting out EPA's secondary (in substance, not just in time) role in developing plans to implement the NAAQS. In fact, the Supreme Court continues to cite these cases for their interpretation of EPA's role. *See West Virginia v. EPA*, 213 L. Ed. 2d 896, 142 S. Ct. 2587, 2600 (2022) ("EPA … does not choose which sources must reduce their pollution and by how much to meet the ambient pollution target. Instead, Section 110 of the Act leaves that task in the first instance to the States, requiring each 'to submit to [EPA] a plan designed to implement and maintain such standards

[46] *See EME Homer*, 572 U.S. at 507 ("The gravamen of the State respondents' challenge ***is not that EPA's disapproval of any particular SIP was erroneous***. Rather, respondents urge that, notwithstanding these disapprovals, the Agency was obliged to grant an upwind State a second opportunity to promulgate adequate SIPs once EPA set the State's emission budget. ***This claim does not depend on the validity of the prior SIP disapprovals***. Even assuming the legitimacy of those disapprovals, the question remains whether EPA was required to do more than disapprove a SIP, as the State respondents urge, to trigger the Agency's statutory authority to issue a FIP.") (emphasis added).

within its boundaries.'") (*quoting Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 65 (1975)).

The SIP Disapproval and RTC makes clear that EPA's disapproval of prong 2 of Minnesota's SIP was not based on a determination that Minnesota's SIP failed to meet the statutory requirements of CAA, but because EPA wanted to apply "a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submissions for the 2015 ozone NAAQS under CAA section 110(a)(2)(D)(i)(I)." SIP Disapproval at 9339; *see also id.* at 9340 ("Effective policy solutions to the problem of interstate ozone transport going back to the NOx SIP Call have necessitated the application of a uniform framework of policy judgments to ensure an 'efficient and equitable' approach.") (quoting *EME Homer*, 572 U.S. at 519); RTC at 425-426. This was error. EPA's assessment of a SIP is to be based on whether the SIP compiles with the requirements of the CAA, not on EPA's policy preferences or desire for efficiency. Only after a state fails to comply with its statutory requirements can EPA impose what it believes best to achieve the substantive objective of the Act.

Because EPA's SIP Disapproval is based on improper factors that undermine the core cooperative federalism embodied in CAA § 110, Petitioners are likely to prevail on the merits of a judicial challenge. This further supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

2. Petitioners Will Suffer Irreparable Harm from a Denial of Stay.

Relevant factors for evaluating the harm which will occur include: (1) the substantiality of the injury alleged; (2) the likelihood of its occurrence; and (3) the adequacy of the proof provided. In evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C.Cir.1985)).

The SIP Disapproval poses substantial and imminent injuries to Petitioners. As discussed in Section II above, the data which EPA should have used to evaluate Minnesota's SIP (see Section II.C), the best available data today, when flaws are addressed (see Sections II.A and B), and even the most likely future data (see Section II.D) strongly support a finding that Minnesota is not significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in any state. EPA's SIP denial is predicated on the erroneous conclusion that there *is* interference with maintenance. This places the entire State of Minnesota in an erroneous state of non-compliance with the Good Neighbor requirement of the Clean Air Act.

EPA's SIP Disapproval also forces EPA to promulgate emission reductions through a FIP. 42 U.S.C. § 7410(c). EPA has already finalized just such a rulemaking. This leaves no time for reconsideration or judicial review to run its course before Petitioners are injured by the FIP, let alone time for Minnesota to remedy EPA's issues with the submitted SIP. Petitioners submitted detailed comments on the FIP identifying numerous substantial injuries from EPA's promulgation

of its Proposed FIP that are likely to occur, and supported by substantial evidence, including detailed technical reports.[47] While EPA made substantial modification to the FIP in response to comments, which Petitioners appreciate reflects considerable work on the Agency's part following the public comment period and has addressed many significant issues with the proposed FIP, the final FIP nonetheless includes significant obligations for Petitioners' electric generating units ("EGUs"), starting in the current 2023 ozone trading season (which begins this year). Even Petitioners without EGUs are substantial consumers of electricity, meaning that they will likely bear much of the burden of the higher costs needlessly imposed on Minnesota power producers because of the FIP. Further, while the Proposed FIP is a separate rulemaking, EPA has itself identified the SIP Disapproval as both a necessary step in issuance of a final FIP[48] and the stay of a SIP disapproval that is the basis for a FIP is an appropriate remedy for injuries arising from the FIP itself. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7, 44 n.6 (D.C. Cir. 2012) (Rogers, J., dissenting), *rev'd on other grounds,* 572 U.S. 489 (2014) ("If [states] wish to avoid enforcement of the Transport Rule FIPs because they contend EPA's SIP disapprovals were in error, the proper course is to seek a stay of EPA's disapprovals in their pending cases; if granted, a stay would eliminate the basis upon which EPA may impose FIPs on those States.") (citing 42 U.S.C. § 7410(c)(1)(B)).

3. Staying the SIP Disapproval will not Significantly Injure Other Parties.

As discussed in Section III.A above, the SIP Disapproval does not on its own impose any emission reductions on sources. As a result, a stay will not directly harm any other party. While a stay would also potentially delay the effective date of the FIP, this is unlikely to result in significant injury to other parties. EPA has recently extended a judicially-enforceable deadline to review Good Neighbor SIPs for three states to December 15, 2023 without any mention of public harm from the delay.[49] Even as a stepping stone to a FIP, while a stay will alleviate imminent and irreparable costs, it will not significantly impact NOx emissions. As discussed above, the FIP is unlikely to be effective until after the start of the current ozone trading season, resulting in an attenuated impact on 2023 emissions. Further, even if projected emission reductions for the full 2023 ozone trading season could be achieved, EPA projects total emission reductions from Minnesota of only 139 tons in 2023. This is unlikely to result in any significant impact on the Cook County maintenance monitor.

4. The Public Interest Lies in Granting a Stay.

As courts have held, there is a public interest enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay.

[47] See Comments of U. S. Steel, EPA-HQ-OAR-2021-0668-0798 (June 27, 2022); Comments of Xcel Energy, EPA-HQ-OAR-2021-0668-0411 (June 23, 2022); Comments of Minnesota Power, EPA-HQ-OAR-2021-0668-0539 (June 23, 2022); Comments of SMMPA, EPA-HQ-OAR-2021-0668-0351 (June 22, 2022); Comments of Cleveland-Cliffs Inc., EPA-HQ-OAR-2021-0668-0405 (June 23, 2022)

[48] 88 Fed. Reg. 9336 at 9362.

[49] *See* Joint Notice of Second Stipulated Extension of Consent Decree Deadlines, Doc. 33, *Downwinders at Risk v. Regan*, Case No. 4:21-cv-3551-DMR (N.D. Cal. Jan. 30, 2023).

As discussed in Section II.A above, EPA's SIP Disapproval was promulgated through the inequitable exclusion of public participation into the data central to EPA's final rulemaking. The result will be costly public expenditures, both by EPA to promulgate an unnecessary FIP and States to either prepare to implement EPA's FIP or prepare revised SIPs, and well as unnecessary costs borne by Petitioners.

While it was an error for EPA to disapprove Minnesota's SIP based on information not in the record at the time of submission, EPA can ameliorate the harm of this error by staying the effect of its SIP disapproval until the merits of the issues above can be fully evaluated and addressed.

IV. Conclusion

The State of Minnesota has expended substantial effort and resources to regulate the emission of NOx within its borders. Those efforts have successfully reduced State impacts on downwind receptors to a point that Minnesota is not a significant contributor to nonattainment or interference with maintenance of the 2015 ozone standard in any state. Based on the best available data and modeling science available at the time, Minnesota assessed its impact on downwind states, as it was required to do under the Clean Air Act, and appropriately concluded that it was not interfering with maintenance of attainment in any state. EPA has identified no error or omission in Minnesota's analysis. Nonetheless, based on data that was not available at the time, and in fact was not available to the public until February 2023, EPA partially disapproved Minnesota's Good Neighbor plan for the sole reason that, based on EPA's own modeling, it found a single maintenance receptor in Cook County, Illinois that Minnesota state emissions were impacting at a maximum level of 0.85 ppb. Neither Minnesota, nor Petitioners, were given an opportunity to comment on EPA's modeling, fully evaluate it, or even see it, until EPA published its final SIP Disapproval. While a complete analysis of EPA's modeling would require months, based on Petitioners' review of the data specific to them, and based on expert evaluations by Alpine Geophysics of the modeling and data EPA has provided, EPA's results likely overstate the impact Minnesota is having on the Cook County monitor. Because Petitioners have provided new information that reveals flaws in EPA's emissions inventory for Minnesota and bias in EPA's modeling of the lone monitor that links Minnesota emissions to a downwind state, Petitioners have raised material new data undermining the central basis for EPA's disapproval of prong 2 of Minnesota's SIP. Petitioners therefore request that EPA grant reconsideration of its partial SIP disapproval for Minnesota and approve Minnesota's 2018 SIP. Further, to avoid the significant and irreparable harm to Petitions arising from EPA's erroneous disapproval of prong 2 of Minnesota's SIP, EPA should stay the effectiveness of its SIP Disapproval as applied to prong 2 of Minnesota's SIP pending reconsideration and pending judicial review.

Dated: April 14, 2023

Respectfully submitted,
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Attachment A

TECHNICAL REVIEW OF THE ENVIRONMENTAL PROTECTION AGENCY'S DENIAL OF MINNESOTA'S 2015 OZONE TRANSPORT SIP

Prepared by:

Alpine Geophysics, LLC

April 2023

Certified by:

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DOCUMENT OBJECTIVE

The objective of this document is for Alpine Geophysics, LLC to provide technical review and professional opinion of Minnesota Pollution Control Agency's (MPCA) SIP revision to address Clean Air Act (CAA) Section 110(a)(2)(D)(i)(I) and the Environmental Protection Agency's (EPA) final action to disapprove the Minnesota State Implementation Plan (SIP) published on February 13, 2023 in the Federal Register.

This document is formatted into three sections that discuss our review and assessment of the following issues:

A. Whether, given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states;
B. Whether U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary; and
C. Whether the Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

At the end of this document, we also provide a summary of conclusions (Section D) and a regulatory and legislative timeline of actions taken on Minnesota's 2015 ozone SIP for reference (Section E).

A. Given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states.

EPA provided little time for MPCA to review the significant amount of technical information and associated calculations that were used to justify their disapproval of the Minnesota SIP, especially since EPA used a distinct and largely unrelated modeling platform, emissions inventory, and air quality model to justify its action instead of assessing the platform submitted by MPCA in support of its SIP. Notwithstanding the fact that four years and four months passed since the original Minnesota SIP was submitted to EPA, had appropriate time been given to MPCA to review and address EPA's final disapproval, MPCA could have addressed significant flaws in EPA's modeling that EPA itself should have addressed prior to finalizing any SIP disapproval.

It is our opinion that the U.S. EPA should have approved the MPCA's SIP when it was submitted in 2018. However, since EPA has put forward new modeling, we have reviewed this modeling and found several issues with the emissions that EPA used in the new modeling that weigh against using it as a basis for disapproving the Minnesota SIP.

1. EPA inappropriately revised the emission inventory and conducted new air quality modeling for SIP disapprovals without allowing a meaningful opportunity for stakeholder review and comment.

EPA's revisions to the emission inventory used in the modeling it previously has conducted for historic transport rules raises an administrative concern about public review and comment.

EPA notes in the proposed SIP disapprovals that, after the modeling it conducted in support of earlier transport rules, e.g., CAIR, CSAPR, CSAPR Update, CSAPR Closeout, and Revised CSAPR Update, the agency revised the emission inventory used in the modeling to assess the efficacy of prior transport rules. EPA conducted new modeling using this revised inventory and 2016v2 modeling platform. The agency describes the process as follows:

> *Following the Revised CSAPR Update final rule, the EPA made further updates to the 2016 emissions platform to include mobile emissions from the EPA's Motor Vehicle Emission Simulator MOVES3 model and updated emissions projections for electric generating units (EGUs) that reflect the emissions reductions from the Revised CSAPR Update, recent information on plant closures, and other sector trends. The construct of*

> *the updated emissions platform, 2016v2, is described in the emissions modeling technical support document (TSD) for this proposed rule.*[1]

In December 2021, and in response to EPA requests for inventory review and updates[2,3,4], MPCA and other stakeholders submitted detailed comments on the 2016v2 emission inventory platform to correct errors that existed in that platform. EPA's declared efforts to revise this emission inventory platform at this time raised the question about whether EPA intended to update the modeling that has been used as the basis for the SIP disapprovals and the proposed FIP – but only in support of the final rule. EPA's own summary[5] of the comment process includes the statement that "by spring of 2021 it was necessary to make updates to the inventories to perform credible / defensible modeling in CY2021". In this summary, numerous and significant emission, control, and projection factor changes were requested and only with release of the final SIP denials were the changes shared by EPA for review.

As part of these comments, MPCA submitted comments on the 2016v2 emissions modeling platform (EMP) relative to three areas of improvement within Minnesota:

1. Non-electricity generation stationary (non-EGU) point source emissions controls
2. Future year emissions projections for various point and non-point inventory sectors
3. Stationary point EGU growth rate differences between the ERTAC vs IPM models

Non-EGU point source emissions controls

LADCO worked with member states to identify the highest-emitting sources and applicable control technology information for non-EGU stationary point sources in the region. They generated a spreadsheet with the highest-emitting non-EGU sources in 2016 for each LADCO state, including Minnesota, which also included state updates on emissions control information for listed sources.

A provided spreadsheet identified control information and future emission rate changes for several Minnesota sources within the 2016v2 EMP. The control information identified accounts for the installation of low NOx burners at the taconite facilities in Minnesota as part of the Regional Haze Taconite FIP. Based on MPCA estimates, just under 11,000 tpy in NOx reductions were expected due to the controls required by the Taconite FIP. MPCA noted the importance of

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[1] See: IN, IL, MN, OH, and WI proposal at 87 Fed. Reg. 9838 at 9840

[2] http://views.cira.colostate.edu/wiki/wiki/11208#September-21-2021

[3] https://cleanairact.org/wp-content/uploads/2021/10/Wayland_Monitoring-Modeling-and-Emission-Inventory-Updates_9-30-21-1.pdf

[4] https://www.epa.gov/air-emissions-modeling/2016v2-platform

[5] https://gaftp.epa.gov/Air/emismod/2016/v2/reports/comments/Summary_of_2016v2_comments_by_sector_01312022.pdf

having these significant reductions included in the EPA EMP for non-EGUs and requested that EPA do so.

Below is a summary of approximate NOx emission changes for these sources.

- 2,100 tpy at Minorca Mine
- 2,300 tpy at Hibbing Taconite
- 700 tpy at United Taconite
- 3,600 tpy at US Steel Keetac
- 2,100 tpy at US Steel Minntac

Future year emissions projections for various point and non-point inventory sectors

LADCO used US EPA-generated emissions projection reports and identified a list of SCCs that they believed had incorrect future year projection rates. The 2016v2 EMP projection rates were not found consistent either with real-world emissions trends or regional emissions projection information. It was requested that EPA replace the 2016v2 EMP projections for these sources with the updated rates provided by LADCO.

A spreadsheet was provided that included the list of the SCCs with alternative projection information and LADCO comments on the sources of the alternative information.

Stationary point EGU growth rate differences between the ERTAC vs IPM models

LADCO recognized that EPA used the Integrated Planning Model (IPM) to estimate future year EGU emissions, and that the IPM projection methodology differed from the Eastern Research Technical Advisory Committee (ERTAC) EGU model that is endorsed by the MJOs and most of the states in the eastern half of the country. Minnesota noted support for the use of ERTAC EGU projections in the 2016v2 EMP and asked EPA to consider replacing IPM projections with ERTAC EGU projections for sources in the LADCO region in subsequent modeling platforms.

While most states urged EPA to rely on modeling that accurately reflects current on-the-books regulatory requirements and up-to-date emission inventories, they also strenuously object to the possibility that EPA would conduct any such additional modeling to support a final rule. Furthermore, these states object to EPA not providing the opportunity for those data to be reviewed, analyzed, commented upon, and having those comments addressed by EPA in advance of any final decision on the subject SIP disapproval (or for that matter the related FIP). These concerns were also expressed in July 2021 by several MJOs (WESTAR, LADCO, SESARM, MARAMA, and CENSARA).[6]

[6] https://www.regulations.gov/comment/EPA-HQ-OGC-2021-0692-0012

ALPINE GEOPHYSICS

EPA's Previously Unreleased 2016v3 Modeling Platform

EPA's newest emissions inventory and modeling platform are of central relevance to EPA's final rule. The SIP Disapproval itself identifies EPA's "updates to the 2016v2 inventories and model design to construct a 2016v3 emissions platform which was used to update the air quality modeling" and used "this updated modeling to inform its final action on these SIP submissions.[7]" These data and modeling in fact form the basis for EPA's final disapproval of Minnesota's SIP[8] (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"). This issue also arose only with the publication of the final SIP Disapproval. EPA's publication of its revised emissions inventory and modeling did not occur until then, and states had no access to the data, the modeling, or even the results of EPA's modeling until that time.

In the limited time that states have had with the modeling data, significant errors have been identified. A robust public comment process for these data is necessary to correct all significant errors to ensure that EPA's regulatory decisions are based on valid and accurate information. Within Minnesota alone, some of these errors include the following:

- EPA incorrectly included NOx emissions of 2,822 tons in 2023 for Northshore Mining Co. – Silver Bay in the future year air quality modeling and associated significant contribution calculations but not in the engineering analysis used to calculate state level EGU budgets. The subject boilers have been idled since October 2019 and are expected to have zero emissions in 2023;

- EPA predicts zero emissions at Minnesota Power's Laskin Energy Center units that have been converted to natural gas and expect continued MISO dispatch to support the renewables transition and regional grid needs / constraints;

These errors, and many like these presumed in other states in the modeling platform, may significantly impact the results of EPA's analysis and could be the difference in nonattainment and maintenance determinations or whether Minnesota is having a downwind effect on the lone Illinois maintenance monitor that subjects Minnesota to the Good Neighbor provisions of the Clean Air Act.

It is our opinion that the absence of inclusion of Minnesota's and other stakeholder's valid EMP revision submissions, as requested by EPA, and without a rerun of the air quality model in both the base and projection year simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change

[7] 88 FR 9339
[8] 88 FR 9357

nonattainment designations and linked significance using an updated platform, and needs to be considered before making any final decision on denial of MPCA's SIP.

2. The Cook County, Illinois monitor to which Minnesota is linked, is located at the interface of land and water along Lake Michigan and is not properly characterized by EPA's supporting modeling.

EPA did not make a bias adjustment for the only receptor that EPA found "links" Minnesota to downwind interference with maintenance. Observed values at this location (the Alsip/Village Garage monitor) demonstrate significant model overprediction, justifying the need for adjustments to address bias. While EPA has recently investigated bias in southern Lake Michigan, this assessment selectively analyzed only one monitor, which was not representative of the bias observed at the Village Garage monitor. The failue to adequately address bias in EPA's modeling resulted in an overprediction of ozone. Adjusting for this bias supports the conclusion that the Alsip monitor models in attainment of the 2015 ozone NAAQS and therefore Minnesota is not interfering with maintenance at this monitor. EPA's ozone attainment modeling guidance states that:

> *"[t]he most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for both ozone and PM2.5 and regional haze. If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s)"*

EPA's modeling in support of the SIP disapprovals simulated a national domain using a 12km grid resolution domain wide. While this makes running a national, regional simulation easier from a technical perspective, it neglects the important issue of the complex meteorology and/or land-water interfaces in or near the nonattainment or maintenance monitors of interest. Indeed, EPA's choice of a 12km grid is an arbitrary choice in contravention of its own guidance when modeling Illinois monitors in Cook County because these monitors are at land-water interfaces.

Photochemical modeling along coastlines is complex for two reasons. First, the temperature gradients along land/water interfaces can lead to localized on-shore/off-shore flows; and

secondly, the photochemical model formulation spreads the emissions in a grid cell throughout the full grid volume of the cell.

Figure 1 presents a unique area along Lake Michigan that is challenged by these complex meteorologic issues at land-water interfaces. For the Cook County, Illinois monitor with which Minnesota is linked in this final rule, EPA's published model performance evaluation (MPE) metrics for ozone have been reviewed by Alpine on a day-specific basis.

Figure 1. Lake Michigan shoreline monitors located on land/water interface in Illinois.

Studies indicate that air quality forecast models typically predict large summertime ozone abundances over water relative to land and that meteorology around Lake Michigan is distinctly unique; both shortcomings warrant individualized attention and a finer grid resolution to best explore actual conditions.[9,10,11]

The 3x3 neighborhood of grid cells used in determining the design values of the relative response factor (RRF) at land-water interface monitors extends into the noted water bodies. Under current guidance, the top ten modeled days within this 3x3 matrix are used in determining this RRF for each monitor with any cell identified as 50 percent or more water, except for cells including monitors, which are omitted from the calculations.

Table 1 below provides a list of top 10 days at monitor 170310001 (Alsip/Village Garage), the Cook County monitor in Illinois to which Minnesota is linked, and comparisons of daily modeled

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[9] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[10] Abdi-Oskouei, M. , and Coauthors , 2020: Sensitivity of meteorological skill to selection of WRF-Chem physical parameterizations and impact on ozone prediction during the Lake Michigan Ozone Study (LMOS). J. Geophys. Res. Atmos., 125, e2019JD031971, https://doi.org/10.1029/2019JD031971.
[11] McNider, R. T. , and Coauthors, 2018: Examination of the physical atmosphere in the Great Lakes Region and its potential impact on air quality—Overwater stability and satellite assimilation. J. Appl. Meteor. Climatol., 57, 2789–2816, https://doi.org/10.1175/JAMC-D-17-0355.1.

maximum daily average 8-hour ozone concentrations (highlighted in green) and observations on the same date in 2016 (highlighted in blue). These are the dates selected in EPA's modeling to represent the highest modeled days used in estimating future year design values.

As can be seen in Table 1 below, several days selected for RRF calculation have modeled ozone concentrations that fall outside of normally acceptable normalized bias (NBias) boundaries (±15%), here as the result of over (positive bias) predictions compared to observed concentrations on those days. In fact, at the monitor example below, seven of the ten selected days fall outside of the ±15% bias metric (highlighted in orange in the Table) with a maximum normalized bias of 93.60% (observation was 45.25 ppb and modeled concentration was 87.60 ppb; a difference of over 42 ppb).

When these dates are used, EPA's calculation of future year DV is 68.2 ppb (average) and 71.9 ppb (maximum) using the average RRF of 0.9349, identifying this as a maintenance monitor.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160719	73.25	91.07	83.28	0.9144	24.33
2	20160723	45.25	87.60	81.46	0.9298	93.60
3	20160726	64.33	84.02	80.98	0.9637	30.61
4	20160810	85.88	81.35	77.20	0.9490	-5.27
5	20160803	74.38	81.04	75.31	0.9293	8.96
6	20160725	61.88	80.86	76.84	0.9503	30.67
7	20160722	54.50	79.83	76.28	0.9556	46.48
8	20160718	60.75	79.69	76.94	0.9655	31.18
9	20160804	63.75	76.21	66.23	0.8691	19.54
10	20160603	73.63	75.74	69.82	0.9219	2.87
Avg					**0.935**	

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.935	0.935
Future 2023 DV (ppb)	68.2	71.9

Table 1. List of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

If instead a list of the top 10 days with Nbias values within normal acceptable normalized boundaries (±15%) are used, an alternate RRF value is generated, and future year average and

maximum design values used in the nonattainment / maintenance designation process are recalculated.

Table 2 presents a list of top 10 days where the Nbias value is less than the acceptable ±15% normalized bias boundaries. As is seen in this table, all Nbias values fall within the parameters of the acceptable range and dates from the original top 10 list that were already within the boundaries have been maintained and are now the top 3 modeled days in the new list.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –Bias Adjusted - No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160810	85.88	81.35	77.20	0.9490	-5.27
2	20160803	74.38	81.04	75.31	0.9293	8.96
3	20160603	73.63	75.74	69.82	0.9219	2.87
4	20160618	67.38	74.79	68.50	0.9158	11.00
5	20160619	76.25	72.60	62.88	0.8662	-4.79
6	20160727	68.75	73.92	68.92	0.9324	7.51
7	20160625	68.13	72.99	66.03	0.9046	7.14
8	20160624	74.88	70.49	66.47	0.9430	-5.86
9	20160802	62.50	71.65	66.87	0.9333	14.64
10	20160524	73.50	69.50	64.27	0.9248	-5.44

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.922	0.922
Future 2023 DV (ppb)	67.3	70.9

Table 2. Alternate bias adjusted list of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

As a result of this bias adjusted calculation, the Alsip / Village Garage monitor located in Cook County, Illinois (170310001) has an average RRF of 0.922, resulting in an average 2023 DV of 67.3 ppb and a maximum DV of 70.9 ppb, identifying this monitor as attainment of the 2015 ozone NAAQS.

Under Step 1 of the ozone transport framework established by EPA, this monitor would not be considered as part of the list of receptors in the significant contribution calculation and therefore any linkages from upwind state contributions would be irrelevant.

Since this is the only monitor in which Minnesota is linked as a significant contributor under EPA's modeling, this linkage would be broken, and Minnesota should be removed from the list of contributing states to downwind receptors.

In the Response to Comments document from the rule, EPA attempted to address the bias issue by preparing an analysis at select monitors in the modeling domain. Specifically, EPA notes[12] that,

> *"Even though the EPA disagrees with commenter's assertion to "throw out" specific days at individual monitors for which model performance does not meet the criteria, out of an abundance of caution, the EPA performed a sensitivity analysis for selected receptors in which the projected 2023 DVs and contributions were recalculated after removing individual days that fell outside the Emery et al., criteria for normalized mean bias and/or normalized mean error. The EPA chose receptors in Coastal Connecticut, the Lake Michigan area, Dallas, and Denver for this analysis. The specific receptors included in this sensitivity analysis are Stratford, Connecticut, Chicago/Evanston, Illinois, Dallas/Denton, Texas, and Denver/Rocky Flats, Colorado."* (emphasis added)

While we agree with EPA's technical approach and calculations in their Chicago/Evanston example provided, EPA's selection of the Evanston monitor is questionable as it is the only monitor out of ten in Cook County, Illinois (three which are identified as maintenance) where performance-based recalculation results in higher design values. This is also not the unique, individual monitor to which Minnesota is exclusively linked. Table 3 presents the ten Cook County, Illinois monitors in EPA's modeling results[13].

As presented in Table 2, using bias-adjusted design values for the individual receptor with which Minnesota is linked (170310001), this monitor is calculated to be in attainment of the 2015 ozone NAAQS in 2023. This decrease is also seen in the remaining Cook County monitors that EPA did not consider in its response to comments on the issue.

[12] See pg. 196, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf

[13] https://www.epa.gov/system/files/documents/2023-03/Final%20GNP%20O3%20DVs_Contributions.xlsx

			Upwind State Contribution (ppb)							
Site ID	2023 Avg DV	2023 Max DV	IN	IA	MI	MN	MO	OH	TX	WI
170310001	68.2	71.9	7.11	0.90	1.16	0.85	0.37	0.68	1.09	2.34
170310032	67.3	69.8	8.22	0.79	1.15	0.60	0.62	1.39	1.40	2.21
170310076	67.6	70.4	6.46	0.80	1.07	0.73	0.49	0.62	1.33	2.49
170311003	64.1	64.7	5.70	0.72	1.03	0.37	0.84	1.22	1.67	2.13
170311601	63.8	64.5	5.85	0.61	2.03	0.59	0.44	1.49	0.78	1.63
170313103	58.4	59.6	4.95	0.38	1.44	0.44	0.46	1.08	0.49	2.32
170314002	64.2	67.3	6.71	0.59	1.48	0.62	0.34	1.09	0.95	3.00
170314007	66.8	68.7	5.33	0.41	1.53	0.49	0.53	1.19	1.03	2.81
170314201	68.0	71.5	5.42	0.42	1.56	0.50	0.54	1.21	1.05	2.86
170317002	68.5	71.3	6.55	0.69	1.00	0.38	1.39	1.04	1.95	2.24

Table 3. Future year design values (ppb) and significant contribution calculations of upwind states to monitors in Cook County, Illinois.

Table 4 demonstrates that the Evanston monitor (170317002) in which EPA used to illustrate a noted increase in design value calculations using a bias adjustment calculation was the only monitor out of the ten where the average and maximum design values increased. Had EPA selected any other monitor from Cook County to demonstrate the bias adjustment, their conclusion may have been different than presented in the Response to Comment document.

			EPA Final Rule		Recalculated w/ Bias Adj		
Site ID	State	County	2023 Avg DV	2023 Max DV	2023 Avg DV	2023 Max DV	Bias Adj DV Change
170310001	Illinois	Cook	68.2	71.9	67.3	70.9	Decrease
170310032	Illinois	Cook	67.3	69.8	66.8	69.3	Decrease
170310076	Illinois	Cook	67.6	70.4	65.9	68.7	Decrease
170311003	Illinois	Cook	64.1	64.7	63.3	64.0	Decrease
170311601	Illinois	Cook	63.8	64.5	63.3	63.9	Decrease
170313103	Illinois	Cook	58.4	59.6	58.4	59.6	No Change
170314002	Illinois	Cook	64.2	67.3	63.2	66.3	Decrease
170314007	Illinois	Cook	66.8	68.7	66.7	68.5	Decrease
170314201	Illinois	Cook	68.0	71.5	67.3	70.7	Decrease
170317002	Illinois	Cook	68.5	71.3	69.0	71.8	Increase

Table 4. EPA final rule and bias-adjusted future year design values (ppb) of monitors in Cook County, Illinois.

Additionally, the LMOS 2017 study[14] shows that for Lake Michigan coastal monitors the air quality model even at a 4 km resolution does not simulate the proper timing and structure of the land/lake breeze or the inland penetration of elevated ozone concentrations. A review of this LMOS study[15] states "To reproduce the timing and magnitude of the ozone time series at coastal monitors, ozone production over the lake must be correctly simulated; furthermore, details of the lake breeze must be accurate——timing, horizontal extent, and vertical structure." Based on recommendations from the LMOS 2017 study research team, a horizontal resolution of at most 1.3 km is required to reasonably resolve the complex meteorology of the air/water interface for the great lakes and coastal ocean areas. The LMOS 2017 Study researchers believe that a 1.3 km grid spacing will assist in the resolution of the large ozone concentration gradients that often occur along the shoreline as well as the inland penetration of the lake breeze circulation.

As the Alsip / Village Garage example shows, days where modeled ozone was predicted at concentrations differing up to ± 42 ppb are being used to estimate future year ozone concentrations and to make determinations of nonattainment, maintenance, and significant contribution from upwind sources.

Furthermore, to adequately capture the inland penetration of the lake breeze, the LMOS report also cites the need for accurate Lake Michigan water temperatures and correct model physics options. EPA's use of the Pleim-Xiu Land Service Model (LSM) does not adequately capture the lake breeze inland penetration. A review of wind vector observations (from the Meteorological Assimilation Data Ingest System (MADIS) network) compared to modeled wind vectors on RRF and significantly contributing days at nonattainment monitors highlights the differences in wind direction and speed during many hours of these predicted high ozone episodes.

On many days with relatively simple meteorology, EPA-developed wind fields using the Weather Research and Forecasting (WRF) Model agree with the MADIS observed winds. However, the modeled winds have strong disagreement with the observed meteorology on June 15, July 7, July 27 and August 4, 2016, the four days when the CAMx model predicted the highest ozone concentrations and are thus used in estimating RRFs and future year ozone design values. The following presents an example on August 4, 2016, a day within the top ten highest model estimated MDA8 ozone concentrations at the Alsip / Village Garage monitor.

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[14] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf

[15] Stanier, C. O., & et al. (2021, November). Overview of the Lake Michigan Ozone Study 2017. BAMS, 19.

In Figure 2 below, the black wind vectors are the wind fields used in the CAMx model. For clarity only every third grid cell is presented. The red vectors are the hourly observed wind vectors from the MADIS archive. The hourly results from 1300 CDT through 1600 CDT are presented in these Figures. The observations clearly show a broad persistent land to lake flow along the western shoreline while the model shows a persistent lake to land flow in this same region during this same period. For this timeframe, when the model is estimating the highest ozone for the ozone season at this receptor, the model has the winds flowing from the lake to the shore while the observations are winds flowing from the shore to the lake.

Figure 2 demonstrates that observed winds (red arrows) are seen moving from land to lake along the western shoreline of Lake Michigan, typically associated with clearing events and lower ozone levels in areas in and around Chicago. In contrast, the model (black arrows) shows a lake to land flow, typically associated with higher model predicted ozone concentrations due to the higher reactive photochemistry over water bodies.

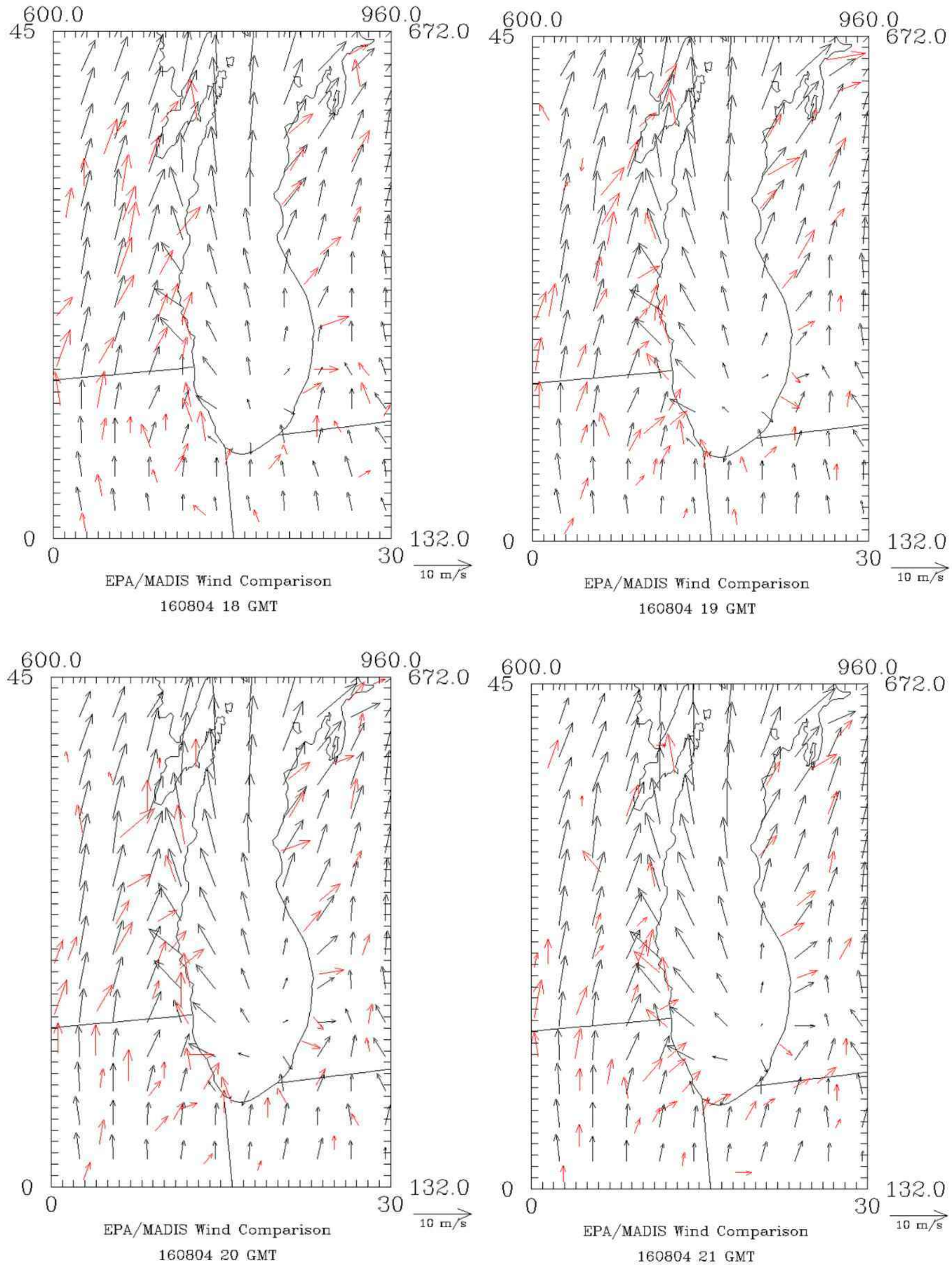

Figure 2. Model estimated (black) and observed (red) winds in the Lake Michigan area at 1300 CDT (top left), 1400 CDT (top right), 1500 CDT (bottom left), and 1600 CDT (bottom right) on August 4, 2016.

These large differences in observed and modeled wind directions are altering the concentration calculations as well as the source/receptor relationships (e.g., determining which sources are "upwind") of the Illinois monitors. As a result, the model cannot accurately reproduce the chemical processes involved with ozone formation. The erroneous modeled meteorological conditions fundamentally change the ozone formation chemistry and modeled source contributions as the chemical transport model predicts more emissions coming from the Chicago urban area than likely the case consistent with the observed wind fields.

When the model is having difficulty resolving fundamental flow patterns in this region with this grid size resolution, EPA needs to reconsider the merit of using the model with this configuration to determine nonattainment status in Step 1 as well as linked significant contributors at receptors in this region under Step 2. For these reasons, EPA must consider finer grid resolution modeling over the Lake Michigan domain to adequately capture ozone formation and significant contribution at receptors located on complex land-water interfaces because model evaluation shows that the model fails to adequately characterize ozone production at these monitors.

Absent a wholesale revision of EPA's modeling protocol, it is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

3. EPA is obligated to address VOC emissions as a critical factor that is influencing ozone nonattainment/maintenance monitors in Illinois

EPA's modeling fails to account for VOC-limited conditions in the Lake Michigan region. Recent information supports the conclusion that VOC-limited conditions in the regional are much more significant that EPA has assumed. This results in EPA's analysis overemphasizing upwind NOx contributions from Minnesota on ozone values at the Alsip/Village Garage monitor and an underemphasis on local VOC contributions, which can be more effectively used to control ozone.

In addition to grid size resolution and complex meteorology issues, modeling performed by EPA[16] and the LMOS 2017 study both showed a negative bias in predicted ozone concentrations in the Lake Michigan region. LMOS 2017 study researchers have experimented with increasing

[16] EPA-HQ-OAR-2021-0668-0099

anthropogenic VOC emissions and decreasing anthropogenic NOx emissions. These emission changes improved air quality model performance reducing the negative bias. VOC speciation and spatio-temporal release patterns should also be reviewed. This evaluation by the LMOS 2017 research scientists indicates there are significant errors in the quantity and speciation of the VOC/NOx emissions used in the EPA's air quality modeling platform to characterize state contribution to ozone in Step 2 of EPA's analyses linking these states to critical nonattainment monitors.

Several downwind nonattainment monitors in urban areas around Lake Michigan recently have been shown to be largely unresponsive to ozone reduction strategies consisting of regional interstate NOx control and that high ozone days in the region were predominantly VOC-limited in nature. This was demonstrated in multiple ozone episodes extensively evaluated in the Lake Michigan Air Directors Consortium (LADCO) Lake Michigan Ozone Study (LMOS) 2017 study[17] where ozone precursor measurements indicated relative increases in VOC concentrations with increases in ozone and where biogenic VOC increases outpaced those of anthropogenic VOC.

In contrast to the peer reviewed research resulting from the 2017 LMOS data collection effort, EPA recently documented its support for additional NOx controls in stating that its "review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[18] However, the current situation is that the modeling as conducted does not accurately characterize ozone levels on high ozone days, underpredicting by 10 + ppb, which is a huge error. Other studies indicate that, to better match actual conditions, the model needs less NOx and higher windspeeds at lower levels. The model is therefore demonstrating that less NOx means more ozone and higher ozone concentrations. That further means that, proportionally, the attribution of ozone to out of state NOx predicts a higher impact than is occurring.

The modeled VOC and NOx emission tracers in EPA's Anthropogenic Precursor Culpability Assessment (APCA) modeling can give a general indication of the VOC/NOx sensitivity, but EPA assigning definitive numerical values to that sensitivity provides inaccurate projections, especially using APCA that is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions. As documented in the CAMx v 7.10 User's Guide[19], "when ozone formation is due to biogenic VOC and anthropogenic NOx under

[17] https://www.ladco.org/wpcontent/
uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[18] 87 Fed. Reg. 20,076
[19] https://camx-wp.azurewebsites.net/Files/CAMxUsersGuide_v7.10.pdf, page 177.

VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NOx present. Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NOx sources and less ozone formation attributed to biogenic VOC sources." Here, it is believed that as applied in this case (with biogenic emissions as an uncontrollable source group), EPA has overestimated the efficacy of NOx controls on these receptors as modeled results have a bias toward attributing more ozone formed to NOx emissions than VOC emissions.

Furthermore, an independent review of EPA's own NOx and VOC contributions challenges the Agency's statement that "[o]ur analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NOX-limited, rather than VOC-limited."[20] This statement is based on all anthropogenic NOx and VOC emissions from all upwind states and is defined as having NOx emissions contribute to 80% or more of the ozone concentrations modeled at each receptor[21].

EPA further goes on to state that "[t]his review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[22]

Alpine's review of EPA's modeled NOx and VOC contributions, by upwind state, focusing on the future year modeled days used in each receptor's Step 2 linkage calculation provides a slightly different picture for monitors around Lake Michigan. As demonstrated in Table 5, of the top future year modeled days impacting significant contribution calculations at the Cook County, Illinois monitor with which Minnesota is linked, more than half of the days are shown to have NOx emission contributions from Illinois below the 80% threshold noted by EPA in determining NOx-limited regions. This is an indicator that on those days, and from anthropogenic sources from those states, VOC controls may demonstrate meaningful impact on ozone concentration reductions at this receptor.

Researchers at the University of Maryland (UMD) have also found in a study of chemical transport model results that by 2023, model predictions of ozone formed under VOC-limited conditions are substantial near the Long Island Sound and the Great Lakes. In a recent presentation[23], they document a source apportionment simulation, conducted with CAMx/APCA on future-year 2023 to determine the major contributing sources and states to air

[20] 87 Fed. Reg. 20053
[21] 87 Fed. Reg. 20076
[22] Id.
[23] https://www.cmascenter.org/conference/2021/slides/allen-northeast-ambient-ozone-2021.pdf

quality within non-attainment areas. Their findings indicate that ozone production under VOC-limited conditions is important at coastal locations near Long Island Sound and the Great Lakes.

		2023 O3	O3N / O3N+O3V Contribution						
Top Day	Date	(ppb)	All	IL	IN	MI	OH	TX	WI
1	07/25/16	70.922	82.4%	81.2%	83.4%	100.0%	-	72.7%	84.1%
2	07/18/16	70.682	69.4%	64.3%	75.6%	-	-	85.9%	67.1%
3	07/19/16	70.668	79.9%	76.7%	83.7%	90.5%	-	80.5%	89.2%
4	08/10/16	67.487	79.4%	70.0%	82.4%	90.4%	86.4%	90.3%	90.6%
5	07/26/16	66.803	80.8%	72.7%	84.0%	90.7%	-	-	90.8%
6	07/23/16	63.295	84.9%	81.2%	84.0%	66.7%	-	89.7%	85.2%
7	08/03/16	61.342	88.8%	84.0%	90.9%	90.4%	92.3%	94.2%	93.8%
8	06/18/16	59.494	86.7%	72.8%	89.4%	90.1%	91.0%	90.9%	89.5%
9	06/03/16	58.730	71.5%	63.2%	73.6%	58.8%	-	74.5%	78.0%
10	08/04/16	58.241	95.0%	92.5%	96.0%	94.7%	97.1%	96.4%	94.9%

Table 5. Modeled ozone contributions to Cook, Illinois monitor (170310001) by percent of emissions from anthropogenic NOx (O3N) compared to emissions from anthropogenic NOx and VOC (O3). Yellow cells indicate contributions of anthropogenic VOC emissions greater than EPA identified "NOx-limited" areas.

Figure 3 presents UMD's findings for model predictions of ozone formation under NOx limited conditions excluding the influence of boundary and initial conditions from the modeling input. As can be seen in these figures, regions around Lake Michigan demonstrate a significantly higher percentage of ozone formed by VOC (blue in color) compared to NOx than most of the eastern US. This observation is seen both on modeled days greater than 60 ppb and on the top ten days of the ozone season (days used in RRF and significant contribution calculations).

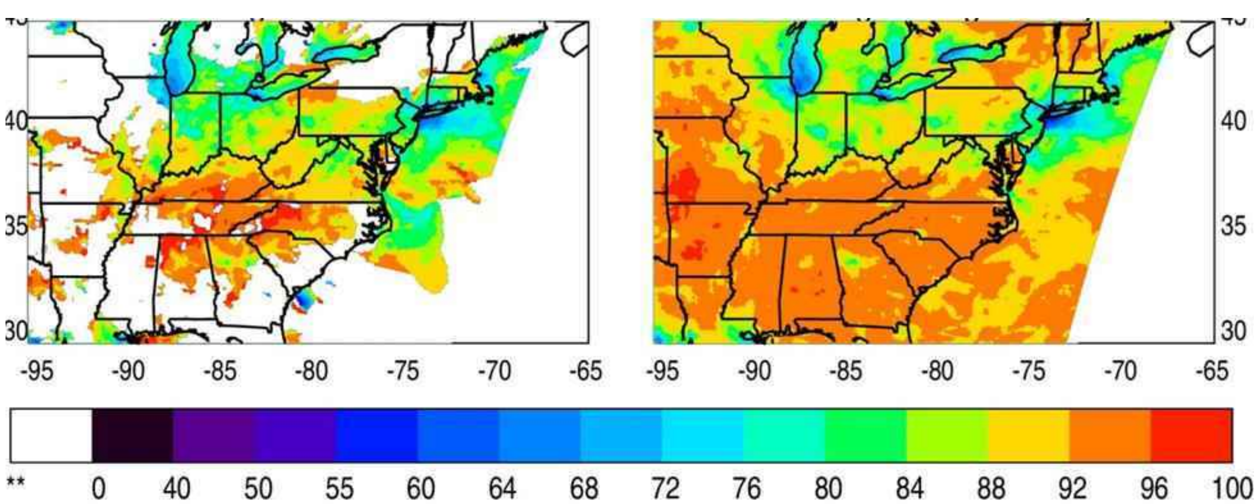

Figure 3. Percent of ozone formed under NOx-limited conditions excluding boundary and initial conditions on all days of MDA8 ozone > 60 ppb (left) and on top ten modeled days (right).

It is also noted that these estimates are a very conservatively high estimate of NOx limited conditions for these coastal areas. In addition to the previous comments highlighting that APCA is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions, the UMD analysis footnotes that the APCA run used to generate the results presented in Figure 3 suggests that model configuration led to an underestimation of the contribution of anthropogenic sources to ozone formation, especially during periods of VOC limited chemistry, and as is seen in Figure 3, in the Cook County, Illinois area.

As a result of these findings, EPA is obligated to address the concern that VOC emissions are a factor that is influencing ozone nonattainment and maintenance monitors in Illinois and elsewhere and that EPA determination of ozone nonattainment or maintenance in these areas may be inappropriate for significant contribution and upwind state linkage calculation. It is also our opinion that after review of VOC contribution and limited ozone reduction potential in Chicago and other noted areas, EPA may find that emission reduction plans may fail to justify regional NOx rules for monitors within these transitional and VOC-limited domains.

B. U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary.

EPA failed to give appropriate recognition of the merit of the MPCA SIP submitted on October 1, 2018, meeting the statutory deadline for submittal of interstate transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

Under the CAA, on April 1, 2019, MPCA's SIP was deemed to be complete since EPA did not act within the 6 months from the date the SIP was submitted. April 1, 2020, 12 months after the completeness date, was the deadline for EPA to have acted on the MPCA SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[24] In this regard, EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

It wasn't until February 22, 2022, three years and four months after submittal, that EPA finally assessed the Minnesota SIP submittal and proposed disapproval of the SIP[25] as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."

The EPA reiterated this assessment and issued a partial approval on February 13, 2023, in their final rule stating that "Although the EPA acknowledges that Minnesota's Step 3 analysis was insufficient in part because the State assumed it was not linked at Step 2, this is ultimately inadequate to support a conclusion that the State's sources do not interfere with maintenance of the 2015 ozone NAAQS in other states in light of more recent air quality analysis."[26]

[24] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

[25] 87 Fed. Reg. 9838

[26] 88 Fed. Reg. 9357

1. EPA's Failure to Act

MPCA has been disadvantaged by EPA's delay in acting to approve or disapprove its 2015 Good Neighbor SIP, which was submitted to EPA on October 1, 2018. EPA published its proposed disapproval on February 22, 2022, and relied in part on newer, updated modeling performed by the EPA which was not available when MPCA submitted its revised SIP. On February 13, 2023, EPA published its final disapproval and again relied on even newer, updated modeling only released with the rule.

By delaying its final decision on Minnesota's submittal for nearly four and a half years, EPA moved the goal post for Minnesota—an act the DC Circuit rebuked in New York v. EPA, 964 F.3d 1214, 1223 (D.C. Cir. 2020). If EPA were to review and approve or disapprove SIPs within the timeframes required by the CAA, EPA would have conducted its review based on the same modeling and data that was available at the time the SIP was submitted and that has been documented in the sections above. EPA offers no indication that additional material information was available to EPA on April 1, 2020, when agency action on the Minnesota SIP was required that could justify disapproval of the Minnesota SIP.

Further, the updated modeling that EPA now offers to support a SIP review has not been adequately available to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval.

2. EPA has not developed any official guidance for states to follow in submitting a Good Neighbor SIP

The Good Neighbor SIP has been a required SIP element since the implementation of the 1997 8- hour ozone standard. In the intervening years, EPA has issued no official guidance for states to use in developing an approvable Good Neighbor SIP. It is unclear what standard or criteria EPA uses to determine approvability.

In its only direction on the subject, EPA released three 2018 memos that included modeling and discussion on potential flexibilities in approaches that could be used by states in developing their Good Neighbor SIPs. However, EPA has now disapproved MPCA's SIP which was based on EPA's own modeling results from the memo because it "does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."[27]

[27] 87 FR 9869

From the memos, the only concrete guidance states have been provided is the four-step framework. Applied appropriately in the MPCA SIP, this framework demonstrated that Minnesota was not significantly linked to any downwind nonattainment or maintenance monitor. Since MPCA used EPA's own modeling and four-step approach to prepare its SIP, the SIP was approvable at the time submitted and was approvable when EPA was required to act on the SIP on April 1, 2020.

3. EPA's ever-changing list of nonattainment and maintenance monitors moves the target for Minnesota without offering any basis to reject MPCA's original analysis.

As detailed earlier, MPCA's air quality projections based on the ozone modeling conducted by LADCO in October 2018 was corroborated by EPA's own contribution modeling released with the March 2018 flexibilities memorandum and that showed that Minnesota was not linked to any monitor designated as nonattainment or maintenance for the 2015 ozone NAAQS in 2023. In those two modeling studies, the Cook County, Illinois monitor now linked to Minnesota was calculated to be in attainment for the 2015 ozone NAAQS.

Table 6 provides the average and maximum projected design values from the LADCO modeling that supported the original MPCA iSIP and March 2018 EPA memo modeling for this monitor demonstrating modeled attainment at this location.

			LADCO Modeling		EPA March 2018 Memo	
AQS Site ID	**State**	**County**	**2023 Average DV**	**2023 Maximum DV**	**2023 Average DV**	**2023 Maximum DV**
170310001	Illinois	Cook	62.8	64.6	63.2	64.9

Table 6. LADCO and EPA 2023 ozone design values (ppb) for Minnesota linked Cook County, Illinois monitor from original MPCA SIP and March 2018 EPA memo modeling results.

EPA's proposed disapproval mentions new modeling conducted by EPA in the interim where this Illinois monitor is ultimately identified as a maintenance monitor. Table 7 below provides the average and maximum projected design values from these studies and from the final SIP disapproval for this monitor.

In the proposed SIP disapproval, EPA cites the "results of a prior round of 2023 modeling using the 2016v1 emissions platform which became available to the public in the fall of 2020 in the Revised CSAPR Update." [28] In this Revised CSAPR Update modeling, developed for use with the 2008 ozone NAAQS analyses, monitor 170310001 is identified as a maintenance monitor in

[28] Footnote 94, 87 FR 9869

EPA's results. In EPA's results published in the proposed SIP disapproval[29] and in the final SIP disapproval[30], EPA continued to identify this monitor as a maintenance monitor.

AQS Site ID	EPA Revised CSAPR Update		EPA Proposed SIP Disapproval		EPA Final SIP Disapproval	
	2023 Ave DV	**2023 Max DV**	**2023 Ave DV**	**2023 Max DV**	**2023 Ave DV**	**2023 Max DV**
170310001	68.4	72.2	69.6	73.4	68.2	71.9

Table 7. EPA 2023 ozone design values (ppb) for Cook County, Illinois monitor from EPA cited modeling results in proposed and final Minnesota SIP disapproval.

In our opinion, EPA should always rely on the best available modeling at the time that an analysis is conducted and results, whether in a SIP or other, are developed and submitted. In this case, EPA has failed to follow this process and instead continued to move the target and objectives for states that, in Minnesota's case, for over four years and four months had been waiting for a review of their "best available data and analysis".

4. Alternative 1 ppb significance threshold

Neither the LADCO modeling nor EPA modeling released with the March 2018 memorandum indicated that Minnesota would contribute over 1% of the NAAQS to any nonattainment or maintenance monitor in 2023. As a result, Minnesota did not think it necessary to consider using a 1 ppb threshold for significant contribution to downwind receptors, which EPA guidance offered as an option to States.

In the SIP disapproval, EPA further elaborates that following their receipt and review of forty-nine good neighbor SIPs for the 2015 ozone NAAQS, their experience was that no state relying on a 1 ppb threshold provided sufficient information and technical support to justify that an alternative threshold was reasonable[31]. EPA does not indicate how many of the reviewed SIPs used a 1 ppb threshold nor do they indicate on how many state SIPs they provided feedback, if any. They go on to state that this alternate 1 ppb threshold may also be politically inconsistent and impractical under the CAA[32].

As EPA not only failed to provide any feedback to Minnesota on its original October 1, 2018 SIP submittal until the February 22, 2022 proposed SIP disapproval, EPA has also failed to honor its March 2018 guidance[33] which was identified to specifically "*provide analytical information*

[29] Table 5, 87 FR 9868
[30] Table III.B-2, 88 FR 9351
[31] 87 FR 9843
[32] Footnote 33, 87 FR 9843
[33] https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf

regarding the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states to downwind receptors or the 2015 ozone NAAQS. It also interprets that information to make recommendation about what thresholds may be appropriate for use in state implementation plan (SIP) revisions addressing the good neighbor provision for that NAAQS."

Minnesota has been denied the opportunity to correct the model inputs that EPA uses as the basis for SIP Disapproval at the 1% threshold and denied the opportunity to update its SIP to take advantage of the 1 ppb threshold that EPA offers States an opportunity to justify in its guidance. While EPA continues to regenerate results based on updated emission modeling platforms and other associated information, states have been omitted from the process, denying them the chance to review updated information and to provide revisions to their SIPs to address those updates.

It is important to note that under all of EPA's cited modeling results, Minnesota contributes under the 1 ppb permitted to be considered from EPA's March 2018 guidance. Table 8 below shows that under none of EPA's four modeling platforms does Minnesota contribute over the 1 ppb threshold to the Cook County monitor.

			Minnesota Contribution (ppb) in 2023			
AQS Site ID	**State**	**County**	**EPA March 2018 Memo**	**EPA Revised CSAPR Update**	**EPA Proposed SIP Disapproval**	**EPA Final SIP Disapproval**
170310001	Illinois	Cook	0.76	0.79	0.97	0.85

Table 8. Minnesota contribution to Cook County, Illinois 2023 ozone design values from documented modeling platforms.

EPA's 2018 flexibility memos, including the opportunity for states to make recommendations to support alternate thresholds for significant contribution, remains an important tool for addressing unique State circumstances in developing their good neighbor SIPs. Disapproving the Minnesota SIP without affording the State an opportunity to utilize this flexibility is unreasonable and should be reconsidered.

C. The Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

1. Introduction

On October 1, 2018, the Minnesota Pollution Control Agency, after review and comment by EPA Region 5 staff, submitted to the U.S. Environmental Protection Agency a request for revision of Minnesota's State Implementation Plan[34].

The proposed SIP revision addressed Minnesota's responsibilities relating to the "Infrastructure" SIP (iSIP) requirements of sections 110(a)(l) and 110(a)(2) of the Clean Air Act (CAA), as they pertain to the National Ambient Air Quality Standard (NAAQS) for ozone, promulgated in 2015. The CAA requires states to submit an iSIP within three years of the EPA's issuance of a new NAAQS to demonstrate their continued ability to implement, maintain, and enforce the federal standards. The iSIP outlined the statutes, rules, and programs that enable Minnesota to ensure attainment of the 2015 ozone NAAQS. These statutes, rules, and programs had previously been reviewed and approved into Minnesota's iSIP, and the materials included with the iSIP demonstrate that the MPCA did not have further obligations under the iSIP requirements.

The MPCA submission utilized both EPA modeling released with a March 2018 flexibilities memorandum[35] and Lake Michigan Air Directors Consortium (LADCO) modeling results[36]. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

In this document we discuss both the technical and legal validity of MPCA's SIP and EPA's obligation to approve the SIP.

EPA's and LADCO's model projections, along with continuing decreases in the emissions and monitored levels of ozone precursors in Minnesota (nitrogen dioxide and volatile organic compounds), demonstrated that no additional controls or emissions limits were necessary to

[34] EPA-R05-OAR-2018-0689-0003
[35] https://www.epa.gov/interstate-air-pollution-transport/memo-and-supplemental-information-regarding-interstate-transport
[36] https://www.ladco.org/wp-content/uploads/Documents/Reports/TSDs/O3/LADCO_2015O3iSIP_TSD_13Aug2018.pdf

fulfill Minnesota's responsibilities under the good neighbor provisions for the 2015 ozone NAAQS.

On February 13, 2023, almost four and a half years after the original SIP submittal, EPA finalized a rule in connection with the Air Plan Disapprovals; Interstate Transport Requirements for the 2015 8-Hour Ozone National Ambient Air Quality Standards[37].

EPA notes in this final rule, that these disapprovals would not start a mandatory sanctions clock but rather would establish a 2-year deadline for EPA to promulgate a Federal Implementation Plan (FIP), unless EPA were to approve a subsequent SIP submittal that meets CAA requirements. EPA originally proposed a FIP to be finalized December 15, 2022, in complete disregard for the 2-year period allowed by the CAA for responding to any such SIP disapprovals[38]. This FIP[39] was signed by the Administrator on March 15, 2023, and is still awaiting publication in the Federal Register.

In 2018 EPA issued flexibility guidance for states to follow in development of 2015 ozone standard NAAQS God Neighbor SIPs (GNS). We specifically question how EPA's late disapproval contradicts this guidance.

2. MPCA's Modeling Approach

The modeling performed to support the SIP was performed by LADCO and except for the 2023 projected EGU emissions, was identical to the "EN" platform developed by EPA and followed EPA guidance[40] in preparation of technical material for SIP and SIP-related modeling. The EN platform was used by EPA in its March 2018 flexibility memorandum so that "[s]tates can use these data to develop their implementation plans to assure that emissions within their jurisdictions do not contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone standards in other states."

In our opinion, this platform was technically credible, and a SIP developed from these data should have been approvable by EPA at the time of submission in October 2018. The following sections present our opinions on specific technical aspects of MPCA modeling.

[37] Id.
[38] 87 Fed. Reg 20036
[39] https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf
[40] https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

Base Year

The base year for the MPCA modeling was 2011. 2011 was selected because of data availability and because EPA[41] had noted that 2011 meteorology in the Eastern U.S., including the upper Midwest, was warmer and drier that the climatic norm and represented typical conditions conducive to high observed ozone concentrations in the Midwest and Northeast U.S. It is Alpine's opinion that 2011 was an appropriate modeling year.

Model and Data Selection

This section introduces the models and data sources used in the MPCA. The selection methodology followed EPA's guidance for ozone regulatory modeling[42],[43],[44]. EPA's 2018 modeling guidance[45] lists several criteria for model selection that are paraphrased as follows (pp. 24-27):

- It should not be proprietary;
- It should have received a scientific peer review;
- It should be demonstrated to be applicable to the problem on a theoretical basis;
- It should be used with data bases which are available and adequate to support its application;
- It should be shown to have performed well in past modeling applications;
- It should be applied consistently with an established protocol on methods and procedures;
- It should have a user's guide and technical description;
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable; and

[41] Air Quality Modeling Technical Support Document for the 2008 Ozone NAAQS Cross-State Air Pollution Rule Proposal. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2015-11/documents/air_quality_modeling_tsd_proposed_rule.pdf

[42] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Research Triangle Park, NC. EPA-454/B-07-002. April, 2007. (http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf).

[43] Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, RTP, NC. December 3, 2014. (http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf).

[44] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[45] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

- When other criteria are satisfied, resource considerations may be important and are a legitimate concern.

It is Alpine's opinion that the models chosen for the MPCA modeling met these criteria and were appropriate for use in the SIP.

Meteorological Modeling

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs[46],[47],[48]. The Advanced Research WRF (ARW) version of WRF was used in the MPCA modeling study. It features multiple dynamical cores, a 3-dimensional variational (3DVAR) data assimilation system, and a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from meters to thousands of kilometers. The effort to develop WRF has been a collaborative partnership, principally among the National Center for Atmospheric Research (NCAR), the National Oceanic and Atmospheric Administration (NOAA), the National Centers for Environmental Prediction (NCEP) and the Forecast Systems Laboratory (FSL), the Air Force Weather Agency (AFWA), the Naval Research Laboratory, the University of Oklahoma, and the Federal Aviation Administration (FAA). WRF allows researchers the ability to conduct simulations reflecting either real data or idealized configurations. WRF provides operational forecasting a model that is flexible and efficient computationally, while offering the advances in physics, numerics, and data assimilation contributed by the research community.

WRF is publicly available, has full documentation and has demonstrated success in simulating meteorological conditions in the Upper Midwest.

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[46] Skamarock, W. C. 2004. Evaluating Mesoscale NWP Models Using Kinetic Energy Spectra. *Mon. Wea. Rev.*, Volume 132, pp. 3019-3032. December, 2004. (http://www.mmm.ucar.edu/individual/skamarock/spectra_mwr_2004.pdf).

[47] Skamarock, W. C. 2006. Positive-Definite and Monotonic Limiters for Unrestricted-Time-Step Transport Schemes. *Mon. Wea. Rev.*, Volume 134, pp. 2241-2242. June. (http://www.mmm.ucar.edu/individual/skamarock/advect3d_mwr.pdf).

[48] Skamarock, W. C., J. B. Klemp, J. Dudhia, D. O. Gill, D. M. Barker, W. Wang and J. G. Powers. 2005. A Description of the Advanced Research WRF Version 2. National Center for Atmospheric Research (NCAR), Boulder, CO. June. (http://www.mmm.ucar.edu/wrf/users/docs/arw_v2.pdf)

MPCA used the U.S. EPA 2011 WRF data for this study[49]. The U.S. EPA used version 3.4 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2011 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation (FDDA) configuration are detailed in the U.S. EPA 2008 Transport Modeling technical support document[50]. U.S. EPA prepared the WRF data for input to CAMx with version 4.3 of the WRFCAMx software.

It is Alpine's opinion that the U.S. EPA WRF 3.4 meteorological modeling was appropriate for use in the MPCA SIP.

Initial and Boundary Conditions

MPCA used 2011 initial and boundary conditions for CAMx generated by the U.S. EPA from the GEOS-Chem Global Chemical Transport Model[51]. EPA generated hourly, one-way nested boundary conditions (i.e., global-scale to regional-scale) from a 2011 2.0 degree x 2.5 degree GEOS-Chem simulation. Following the convention of the U.S. EPA O3 transport modeling, year 2011 GEOS-Chem boundary conditions were used by LADCO for modeling 2023 air quality with CAMx.

It is Alpine's opinion that the U.S. EPA GEOS-Chem derived initial and boundary conditions were appropriate for use in the MPCA SIP.

Emissions

The 2023 emissions data for the MPCA SIP were based on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform[52]. U.S. EPA generated this platform for their final assessment of Interstate Transport for the 2008 O3 NAAQS. Updates from earlier 2011-based emissions modeling platforms included a new engineering approach for forecasting emissions from Electricity Generating Units (EGUs). LADCO replaced the EGU emissions in the U.S. EPA EN

[49] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[50] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

[51] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[52] US EPA. 2017. Technical Support Document: Additional Updates to Emissions Inventories for the Version 6.3 Emissions Modeling Platform for the Year 2023. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-11/documents/2011v6.3_2023en_update_emismod_tsd_oct2017.pdf

platform with 2023 EGU forecasts estimated with the ERTAC EGU Tool version 2.7[53]. ERTAC EGU 2.7 integrates state-reported information on EGU operations and forecasts as of May 2017. The MPCA believes "power sector emissions forecasts must address economic factors, preserve system reliability, and include controls or emission reduction measures justified through some legal framework. It is our understanding that the engineering analysis used by EPA to project EGU emissions to 2023 (version EN of the modeling platform) does not comply with these key requirements. The ERTAC estimates incorporate the key requirements."[54]

In March 2018 U.S. EPA released it flexibilities memo that described a series of flexibilities that states could consider in developing Good Neighbor SIPs for the 2015 ozone NAAQS. The "[u]se of alternative power sector modeling consistent with EPA's emissions inventory guidance" is presented in the Analytics section of EPA's March 2018 memo as a flexibility to consider in preparing a Good Neighbor SIP. This flexibility supports LADCO's use of the ERTAC EGU model for projecting EGU emissions to 2023. MPCA considers the emissions projections from ERTAC EGU to be more representative of the sources in the Midwest and Northeast than the approach used by U.S. EPA in their 2023 EN modeling platform. As ERTAC EGU is developed in collaboration between regional and state air planning agencies, it includes algorithms and data that have been reviewed by many of the states impacted by interstate O3 transport in the Midwest and Eastern U.S.

Preparation of the emissions data to support photochemical models is a very complicated process that entails the use of a number of different "sub-models" to prepare different emission segments.

Sparse Matrix Operator Kernel Emissions (SMOKE)

The Sparse Matrix Operator Kernel Emissions (SMOKE) is an emissions modeling system that generates hourly gridded speciated emission inputs of mobile, non-road, area, point, fire and biogenic emission sources for PGMs[55],[56]. As with most "emissions models," SMOKE is principally an emission processing system and not a true emissions modeling system in which emissions estimates are simulated from "first principles." This means that, except for mobile and biogenic sources, its purpose is to provide an efficient, modern tool for converting an existing base emissions inventory data that is typically at the county or point source level into

[53] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[54] EPA-R05-OAR-2018-0689-0003

[55] Coats, C.J. 1995. Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, MCNC Environmental Programs, Research Triangle Park, NC.

[56] UNC. 2018. SMOKE v4.6 User's Manuel. University of North Carolina at Chapel Hill, Institute for the Environment. Chapel Hill, North Carolina. September 24. (https://www.cmascenter.org/smoke/documentation/4.6/manual_smokev46.pdf).

the hourly gridded speciated formatted emission files required by a Photochemical Grid Model (PGM), like CAMx. SMOKE was used to prepare emission inputs for non-road mobile, non-point (area) and point sources. SMOKE performs three main function to convert emissions to the hourly gridded emission inputs for a PGM: (1) spatial allocation, spatial allocates county-level emissions to the PGM model grid cells typically using a surrogate distribution (e.g., population); (2) temporal allocation, allocates annual emissions to time of year (e.g., monthly or seasonally) and day-of-week (typically weekday, Saturday and Sunday); and (3) chemical speciation, maps the emissions to the species in the chemical mechanism used by the photochemical grid model, most important for VOC and $PM_{2.5}$ emissions.

The primary emissions modeling tool used to create the air quality model-ready emissions was the SMOKE modeling system version 3.7 which was used to create emissions files for a 12-km national grid "12US2" that includes all of the contiguous states.

It is Alpine's opinion that the SMOKE emissions model together with the other EPA emissions was appropriate for use in the MPCA SIP.

Motor Vehicle Emissions Simulator (MOVES)

The motor vehicle emissions were prepared by U.S. EPA using the MOVES 2014a emissions model[57],[58],[59]. MOVES 2014a was the most up to date released motor vehicle emissions processor at the time of the MPCA SIP submission and it is Alpine's opinion that the U.S. EPA MOVES 2014a emissions were appropriate for use in the MPCA SIP.

Eastern Regional Technical Advisory Committee EGU Model

The Eastern Regional Technical Advisory Committee (ERTAC) EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emissions projections. States needed a transparent model that was numerically stable and did not produce dramatic changes to the emissions forecasts with small changes in inputs. A key feature of the model

[57] EPA. 2014a. Motor Vehicle Emissions Simulator (MOVES) – User Guide for MOVES2014. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-055). July. (http://www.epa.gov/oms/models/moves/documents/420b14055.pdf).

[58] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

[59] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

includes data transparency; all of the inputs to the model are publicly available. The code is also operationally transparent and includes extensive documentation, open-source code, and a diverse user community to support new users of the software.

Operation of the model is straightforward given the complexity of the projection calculations and inputs. The model imports base year Continuous Emissions Monitoring (CEM) data from U.S. EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off-peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve capacity, generates quality assurance reports, and converts the outputs to SMOKE ready modeling files.

ERTAC EGU has distinct advantages over other growth methodologies because it can generate hourly future year estimates which are key to understanding ozone episodes. The model does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Full documentation for the ERTAC Emissions model and 2.7 simulations are available through the MARAMA website[60].

Differences between the EPA and ERTAC EGU emissions forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions. The U.S. EPA EGU forecast used in the 2023 EN modeling used CEM data available through the end of 2016 and comments from states and stakeholders received through April 17, 2017[61]. ERTAC EGU 2.7 used CEM data from 2011 and state-reported changes to EGUs through May 2017. The ERTAC EGU 2.7 emissions used for the modeling represented the best available information on EGU forecasts for the Midwest and Eastern U.S. available during Spring-early Summer 2018.

The “consideration of state-specific information in identifying sources [e.g., electric generating units (EGUs) and non-EGUs] and controls” is one of the potential approaches in EPA’s March 2018 flexibilities memorandum. The use of the ERTAC EGU tool falls squarely within the parameters of this documented flexibility and it is Alpine’s opinion that MPCA’s used of EGU emission projections from this model were appropriate in the MPCA SIP.

[60] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[61] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

BEIS

Biogenic emissions were computed by U. S. EPA based on the same version of the 2011 meteorology data used for the air quality modeling and were developed using the Biogenic Emission Inventory System version 3.61 (BEIS3.61) within SMOKE. The landuse input into BEIS3.61 is the BELD version 4.1 which is based on an updated version of the USDA-USFS Forest Inventory and Analysis (FIA) vegetation speciation-based data from 2001 to 2014 from the FIA version 5.1.

It is Alpine's opinion that the U.S. EPA application of the BEIS model was appropriate for use in the MPCA SIP.

3. Air Quality Modeling

The MPCA modeling used the Comprehensive Air-quality Model with Extensions (CAMx) air quality model[62]. CAMx is a state-of-science "One-Atmosphere" multi-scale photochemical grid model (PGM) capable of addressing ozone, particulate matter (PM), visibility and acid deposition at regional, urban and local scale typically for periods of a year. CAMx is a publicly available open-source computer modeling system for the integrated assessment of gaseous and particulate air pollution. Built on today's understanding that air quality issues are complex, interrelated, and reach beyond the urban scale, CAMx is designed to (a) simulate air quality over many geographic scales, (b) treat a wide variety of inert and chemically active pollutants including ozone, inorganic and organic $PM_{2.5}$ and PM_{10} and mercury and toxics, (c) provide source-receptor, sensitivity, and process analyses and (d) be computationally efficient and easy to use.

The U.S. EPA has approved the use of CAMx for numerous ozone and PM State Implementation Plans throughout the U.S. and has used this model to evaluate regional mitigation strategies including those for most recent national transport rules, such as the Cross-State Air Pollution Rule (CSAPR), CSAPR Update, and the modeling used in justification of denial of the MPCA SIP. The MPCA used Version 6.4, which was released in December 2016. Unlike some of EPA's previous ozone modeling guidance that specified a particular ozone model (e.g., EPA 1991 Guidance[63]) or that specified the Urban Airshed Model (UAM)[64], the EPA now recommends that

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[62] User's Guide: Comprehensive Air Quality Model with Extensions version 6.40. Novato, CA. http://www.camx.com/files/camxusersguide_v6-40.pdf

[63] Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-hr Ozone NAAQS". U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. May.

[64] User's Guide for the Urban Airshed Model. Volume I: User's Manual for UAM (CB-IV) prepared for the U.S. Environmental Protection Agency (EPA-450/4-90-007a). Systems Applications International, San Rafael, CA.

models be selected for ozone SIP studies on a "case-by-case" basis. The latest EPA ozone guidance[65] (pp. 24) explicitly mentions the CAMx PGMs as one of the most commonly used PGMs that would satisfy EPA's selection criteria but notes that this is not an exhaustive list and does not imply that it is "preferred" over other PGMs that could also be considered and used with appropriate justification.

The CAMx model is updated regularly to both update the science in the model and to address coding errors (bugs) in the code. CAMx 6.5 was released at the end of April 2018, approximately 6 months prior to submission the MPCA SIP submission. It is customary for regulatory modeling to "freeze" the model version during the modeling process to keep the modeling on schedule.

It is Alpine's opinion that the CAMx 6.4 air quality model along with the EPA EN platform with 2023 EGU's updated to include ERTAC was appropriate for use in the MPCA SIP.

4. Model Performance

MPCA relied on the model performance evaluation (MPE) conducted by the U.S. EPA on the modeling platform that we used for this study[66] to establish validity in the modeling platform. In addition to the MPE for the base year CAMx simulation, the U.S. EPA reported full MPE results for the 2011 WRF modeling[67] used in the CAMx simulations.

It is Alpine's opinion that the EPA WRF and CAMx performance evaluations showed adequate performance and that the modeling was appropriate for use in the MPCA SIP.

5. Source Apportionment

MPCA used the CAMx Anthropogenic Precursor Culpability Assessment (APCA) tool to calculate emissions tracers for identifying upwind sources of ozone at downwind monitoring sites. MPCA

[65] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[66] US EPA. 2016. Air Quality Modeling Technical Support Document for the 2015 Ozone NAAQS Preliminary Interstate Transport Assessment. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-01/documents/aq_modeling_tsd_2015_o3_naaqs_preliminary_interstate_transport_assessmen.pdf

[67] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

used the APCA technique because it more appropriately associates ozone formation to anthropogenic sources than the CAMx Ozone Source Apportionment Technique (OSAT). If any anthropogenic emissions are involved in a reaction that leads to ozone formation, even if the reaction occurs with biogenic VOC or NOx, APCA tags the ozone as anthropogenic in origin.

The APCA source apportionment tool has a robust theoretical basis and a long application history and it is our opinion that the APCA tool is appropriate for identifying upwind sources of ozone at downwind monitoring sites.

6. Interstate Transport Provisions – Section 110(a)(2)(D)

This section of the CAA requires SIPs to have provisions prohibiting sources from emitting air pollutants in amounts that would contribute significantly to nonattainment or interfere with maintenance in any other state. These interstate transport requirements are often referred to as "good neighbor SIPs". The analyses conducted both by LADCO and EPA to support the 2015 ozone good neighbor SIPs show Minnesota does not contribute significantly to air quality problems in any downwind nonattainment or maintenance area. Therefore, no additional controls or emissions limits were required to fulfill Minnesota's good neighbor obligations.

On March 27, 2018, the EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". EPA's Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

EPA identifies a four-step framework in the Memo, intended to guide states on how to go about developing good neighbor SIPs:

1. Identify downwind air quality problems;
2. Identify upwind states that contribute enough to those downwind air quality problems to warrant further review and analysis;
3. Identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems; and
4. Adopt permanent and enforceable measures needed to achieve those emissions reductions.

In Step 1, EPA identifies monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS in the 2023 analytic year. Where EPA's analysis shows that a site does

not fall under the definition of a nonattainment or maintenance receptor, that site is excluded from further analysis under EPA's 4-step interstate transport framework. For sites that are identified as a nonattainment or maintenance receptor in 2023, we proceed to the next step of our 4-step interstate transport framework by identifying the upwind state's contribution to those receptors.

In Step 2, EPA quantifies the contribution of each upwind state to each receptor in the 2023 analytic year. The contribution metric used in Step 2 is defined as the average impact from each state to each receptor on the days with the highest ozone concentrations at the receptor based on the 2023 modeling. If a state's contribution value does not equal or exceed the threshold of 1 percent of the NAAQS (i.e., 0.70 ppb for the 2015 ozone NAAQS), the upwind state is not ''linked'' to a downwind air quality problem, and EPA, therefore, concludes that the state does not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in the downwind states.

Comparably, in MPCA's SIP submission, they include LADCO's modeling which additionally follows the same transport framework and is corroborated by EPA's modeling with the data released with the March 2018 memo.

Step 1 - 2023 Air Quality Projections

MPCA's reported air quality projections[68] submitted with their SIP were based on the ozone modeling conducted by LADCO. The result of this LADCO 2023 modeling, using methods utilized by EPA and shown in Table 9 below, forecasted that no downwind monitors in the Midwest or Northeast would be nonattainment for the 2015 O3 NAAQS.

[68] Data source Table 5, Attachment 1, EPA-R05-OAR-2018-0689-0003

			LADCO 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	67.2	69.4	78.0	80.0
90013007	Fairfield	CT	67.8	71.6	84.3	89.0
90019003	Fairfield	CT	69.6	72.4	83.7	87.0
90099002	New Haven	CT	67.9	70.5	85.7	89.0
240251001	Harford	MD	69.4	71.8	90.0	93.0
260050003	Allegan	MI	67.1	69.8	80.3	83.0
261630019	Wayne	MI	67.7	69.7	78.7	81.0
360810124	Queens	NY	67.5	69.2	70.0	71.0
361030002	Suffolk	NY	69.8	71.3	83.3	85.0
550790085	Milwaukee	WI	62.1	65.1	78.3	82.0
551170006	Sheboygan	WI	69.3	71.5	84.3	87.0

Table 9. LADCO 2023 ozone design values at EPA identified nonattainment and maintenance monitors in the Midwest and Northeast.

EPA's own modeling[69], released with the March 2018 platform, shown in Table 10, and designed to be used by states in development of their ozone transport SIPs, indicated that in the Midwest or Northeast, two downwind monitors in Fairfield, Connecticut (monitors 90013007 and 90019003), a monitor in Suffolk, New York (36103002), and monitors in Milwaukee (550790085) and Sheboygan (551170006), Wisconsin would be in nonattainment for the 2015 ozone NAAQS.

			EPA 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	68.9	71.2	80.3	83.0
90013007	Fairfield	CT	71.0	75.0	84.3	89.0
90019003	Fairfield	CT	73.0	75.9	83.7	87.0
90099002	New Haven	CT	69.9	72.6	85.7	89.0
240251001	Harford	MD	70.9	73.3	90.0	93.0
260050003	Allegan	MI	69.0	71.7	82.7	86.0
261630019	Wayne	MI	69.0	71.0	78.7	81.0
360810124	Queens	NY	70.2	72.0	78.0	80.0
361030002	Suffolk	NY	74.0	75.5	83.3	85.0
550790085	Milwaukee	WI	71.2	73.0	80.0	82.0
551170006	Sheboygan	WI	72.8	75.1	84.3	87.0

Table 10. EPA 2023 ozone design values at nonattainment and maintenance monitors in the Midwest and Northeast.

[69] https://www.epa.gov/sites/default/files/2018-05/updated_2023_modeling_dvs_collective_contributions.xlsx

An additional six monitors in Connecticut (90010017 and 90099002), Maryland (240251001), Michigan (260050003 and 261630019), and New York (360810124) would be considered maintenance monitors in the projection.

In neither the LADCO nor EPA modeling cited in MPCA's SIP revision submission were the two Cook County, Illinois monitors (170314201 and 170310076) from EPA's SIP denial NPR, or the single monitor from EPA's final SIP disapproval action, identified as either nonattainment or maintenance monitors in the 2023 projections.

Step 2 - Significant Contribution to Downwind States

EPA has previously determined that a state contribution to downwind air quality problems below one percent of the applicable NAAQS is insignificant. This screening method was used in previous good neighbor SIP approvals, and other regulatory actions including (most notably) the Cross-State Air Pollution Rule (CSAPR), and the CSAPR update for the 2008 ozone NAAQS and 2012 NAAQS for particulate matter less than 2.5 micrometers in diameter (PM2.5). The one percent screening method was developed through several previous federal notice and comment rulemakings. One percent of the 2015 ozone NAAQS (70 ppb) is 0.70 ppb. Therefore, any state that contributes less than 0.70 ppb to a projected nonattainment or maintenance area in another state is not culpable for those air quality problems.

EPA and LADCO applied the Anthropogenic Precursor Culpability Analysis (APCA) technique in CAMx to identify upwind states culpable for downwind ozone air quality problems. The method accounts for anthropogenic nitrogen oxides (NO_x) and volatile organic carbon (VOC) emissions from all sources in each upwind state affecting projected 2023 ozone concentrations at each downwind air quality monitoring site designated a nonattainment or maintenance receptor. EPA and LADCO conducted the culpability analysis for the period May 1 through September 30, using the 2023 future emission estimates and 2011 meteorology.

Both LADCO and EPA analyses[70] conclude Minnesota is not culpable for ozone nonattainment, or interference with maintenance, in any downwind states. As shown in Table 11, prepared using data from MPCA's SIP[71], LADCO's analysis shows a maximum contribution of 0.45 ppb to the identified maintenance monitors, less than the 0.70 ppb identified as 1% of the NAAQS (70 ppb). EPA's analysis[72] (Table 12) indicates Minnesota contributes most to Milwaukee, Wisconsin monitor site 550790085. At a concentration of 0.40 ppb, this contribution is roughly equal to 0.57% of the 2015 ozone NAAQS.

[70] Data source Table 2, EPA-R05-OAR-2018-0689-0003
[71] Id.
[72] Id.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	67.2	69.4	0.17
90013007	Fairfield	CT	67.8	71.6	0.15
90019003	Fairfield	CT	69.6	72.4	0.11
90099002	New Haven	CT	67.9	70.5	0.16
240251001	Harford	MD	69.4	71.8	0.12
260050003	Allegan	MI	67.1	69.8	0.11
261630019	Wayne	MI	67.7	69.7	0.30
360810124	Queens	NY	67.5	69.2	0.16
361030002	Suffolk	NY	69.8	71.3	0.16
550790085	Milwaukee	WI	62.1	65.1	0.45
551170006	Sheboygan	WI	69.3	71.5	0.27

Table 11. LADCO 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	68.9	71.2	0.17
90013007	Fairfield	CT	71.0	75.0	0.15
90019003	Fairfield	CT	73.0	75.9	0.14
90099002	New Haven	CT	69.9	72.6	0.19
240251001	Harford	MD	70.9	73.3	0.13
260050003	Allegan	MI	69.0	71.7	0.11
261630019	Wayne	MI	69.0	71.0	0.31
360810124	Queens	NY	70.2	72.0	0.17
361030002	Suffolk	NY	74.0	75.5	0.18
550790085	Milwaukee	WI	71.2	73.0	0.40
551170006	Sheboygan	WI	72.8	75.1	0.28

Table 12. EPA 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

For the reasons set forth in this section, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 2018 was technically adequate and appropriate for the purpose it was intended and followed all available EPA guidance on preparing technical modeling for SIP and SIP-related analyses.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted.

D. Summary of Conclusions

For the reasons set forth in this document, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 1, 2018 was technically adequate and appropriate for the purpose it was intended and should have been approved by EPA at the time of submission. It is further our opinion that decisions made by EPA to compare MPCA's original submitted modeling to recently updated modeling, developed by EPA over four years and four months later than the original Oct 2018 submission, are inconsistent with EPA precedent.

It is our opinion that in the absence of inclusion of Minnesota's and other stakeholder's valid emission modeling platform revision submissions, as requested by EPA, and multiple reruns of the air quality in both the base year (2016) and projection year (2023) simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change nonattainment designations and linked significance using an updated platform and needs to be considered before making any final decision on denial of MPCA's SIP.

It is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

It is our opinion that the most recent modeling cited by EPA and used to justify the linkage of Minnesota to one downwind maintenance monitors in Cook County, Illinois has technical issues as it relates to that linked monitor which is located in a complex land-water interface and may require finer grid resolution modeling to adequately capture ozone formation and significant contribution, and that EPA must address the impact of VOC emissions in influencing ozone formation at monitors in Illinois.

It is our opinion that EPA has failed to follow the process by relying on the best available modeling at the time that an analysis is conducted, and results are developed and submitted. Instead, EPA continues to move the target and objectives for states that, in Minnesota's case, for over four years had been waiting for a review of their "best available data and analysis".

It is our opinion that EPA should not have used any updated modeling to support a SIP review while not providing the opportunity for that data to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval and that any modeling beyond what was conducted in the original SIP submittal was ancillary to the approval process. However, should EPA decide not to review MPCA's SIP revision on its merit, Alpine recommends that EPA withdraw the SIP disapproval in favor of correcting the technical errors that have been identified in its analysis and to propose an appropriate opportunity for Minnesota to address any deficiencies EPA may find in Good Neighbor Plans implementing the 2015 ozone NAAQS.

It is our opinion that EPA's 2018 flexibility memo has become so instrumental to states in developing their good neighbor SIPs, that EPA's decision to disallow the flexibilities that they themselves outlined in guidance, is unreasonable and should be reconsidered.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted. It is our opinion that the original MPCA SIP was and is approvable.

E. Minnesota 2015 Ozone SIP Timeline

October 1, 2015 – EPA finalized the revised 2015 ozone NAAQS. Pursuant to CAA section 110(a)(1), "each state shall . . . submit to the Administrator, within 3 years. . .after promulgation of a [primary NAAQS] (or any revision thereof) a plan which provides for implementation, maintenance, and enforcement of such primary standard. . ." CAA section 110(a)(2)(D)(i)(I) requires such SIPs to "contain adequate provisions prohibiting . . .any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, and other State with respect to such NAAQS.

March 27, 2018 - EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". EPA's Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

October 1, 2018 - Minnesota Pollution Control Agency (MPCA) submitted a SIP revision to address CAA Section 110(a)(2)(D)(i)(I) on October 1, 2018 .[73] The submission met the statutory deadline for submittal the interest transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

April 1, 2019 – This is 6 months after EPA received the Minnesota SIP submission and is the date that the CAA deems the Minnesota submittal to have been complete since EPA did not take action otherwise.

September 13, 2019 - The D.C. Circuit issued a decision in *Wisconsin v. EPA*, remanding the CSAPR Update to the extent that it failed to require upwind states to eliminate their significant

[73] **Completeness Finding** - Pursuant to the CAA Section 110(k)(1)(B) "Within 60 days of the Administrator's receipt of a plan or plan revision, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria established pursuant to subparagraph (A) have been met. Any plan or plan revision that a State submits to the Administrator, and that has not been determined by the Administrator (by the date 6 months after receipt of the submission) to have failed to meet the minimum criteria established pursuant to subparagraph (a), shall on that date be deemed by operation of law to meet such minimum criteria."

contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). 938 F.3d at 313.

April 1, 2020 – This is 12 months after the completeness date and is the deadline for EPA to have acted on the MN SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[74]

May 19, 2020 - the D.C. Circuit issued a decision in *Maryland v. EPA* that cited the Wisconsin decision in holding that EPA must assess the impact of interstate transport on air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for EPA's denial of a petition under CAA section 126(b). Maryland v. EPA, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020). The court noted that "section 126(b) incorporates the Good Neighbor Provision," and, therefore, "EPA must find a violation [of section 126] if an upwind source will significantly contribute to downwind nonattainment at the next downwind attainment deadline. Therefore, the agency must evaluate downwind air quality at that deadline, not at some later date." Id. at 1204 (emphasis added). EPA interprets the court's holding in Maryland as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date, which is now the Moderate area attainment date under CAA section 181 for ozone nonattainment. The Moderate area attainment date for the 2015 ozone NAAQS is August 3, 2024. At the time of the statutory deadline to submit interstate transport SIPs (October 1, 2018), many states relied upon EPA modeling of the year 2023, and no state provided an alternative analysis using a 2021 analytic year (or the prior 2020 ozone season). However, EPA must act on SIP submittals using the information available at the time it takes such action. In this circumstance, EPA does not believe it would be appropriate to evaluate states' obligations under CAA section 110(a)(2)(D)(i)(I) as of an attainment date that is wholly in the past, because the Agency interprets the interstate transport provision as forward looking. See 86 FR at 23074; see also Wisconsin, 938 F.3d at 322. Consequently, in this proposal EPA will use the analytical year of 2023 to evaluate each state's CAA section 110(a)(2)(D)(i)(I) SIP submission with respect to the 2015 ozone NAAQS.

May 12, 2021 – Downwinders at Risk, et al filed Case No. 21 Civ. 21 Civ 3551 asserting that EPA failed to undertake certain non-discretionary duties under the CAA.

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[74] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

February 22, 2022 - EPA assessed the Minnesota submittal and on February 22, 2022 (3 years, 4+ months after submittal) the agency proposed denial of the Minnesota SIP as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state. Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838 (Feb. 22, 2022).

February 28, 2022 – EPA and Downwinders et al established in a Consent Decree entered into on 1/12/2022 that if EPA proposed a full or partial denial of the Minnesota SIP EPA shall have until December 15, 2022 to sign a final action. Note this is a settlement and does not erase the fact that EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

April 30, 2022 – EPA and Downwinders, et established in a Consent Decree entered into on 1/12/2022 that required EPA to sign for publication final rulemaking on April 30, 2022 to approve, disapprove, and conditionally approve the Minnesota SIP submissions for the 2015 ozone NAAQS.

May 22, 2022 – EPA proposed to approve most elements of the Minnesota October 1, 2018 submission intended to address all applicable infrastructure requirements for the 2015 NAAQS. (87 FR 31462).

July 29, 2022 – EPA approved most elements of the Minnesota October 1, 2018 SIP submission from Minnesota regarding infrastructure requirements for the 2015 ozone NAAQS. EPA did not act on the interstate transport requirements and visibility impairments requirements. (87 FR 45663).

December 8, 2022 – EPA and Downwinders et al filed a Joint Motion of Stipulated Extension of Consent Decree deadlines that provided the following schedule.

December 15, 2022 – Former agreed upon deadline by Downwinders for EPA to act on Minnesota SIP, but this deadline was moved by agreement to January 31, 2022.

January 31, 2023 - deadline to sign final action on Minnesota SIP pursuant to agreed upon extension of Downwinders Consent Decree.

February 13, 2023 – EPA publishes final disapproval of State Implementation Plan (SIP) submissions for 19 states, including Minnesota. Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336.

March 15, 2023 – EPA issues final federal Good Neighbor Plan for the 2015 ozone NAAQS (publication in the Federal Register is still pending).

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit G

Petition for Reconsideration and Stay of the Final Rule: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards (Aug. 4, 2023)

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August 4, 2023

VIA E-MAIL AND FEDERAL EXPRESS

Michael Regan (Regan.Michael@epa.gov)
EPA Administrator
Office of the Administrator, Mail Code 1101A
United States Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, EPA–HQ–OAR–2021–0668, 88 Fed. Reg. 36,654 (June 5, 2023)

Dear Administrator Regan:

On behalf of our clients, ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively the "Minnesota Good Neighbor Coalition"), please find enclosed a petition for reconsideration and stay of the portion of the Environmental Protection Agency's final rule Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0668; 88 Fed. Reg. 36,654 (June 5, 2023) that imposes a federal implementation plan on Minnesota for interstate transport of ozone under "prong 2" of the Clean Air Act, 42 U.S.C. § 7410(a)(2)(D)(i)(I).

Please contact me with any questions you may have.

Sincerely,

/s/ Douglas A. McWilliams
Douglas A. McWilliams

Enclosure

cc: Elizabeth Selbst (selbst.elizabeth@epa.gov)
Gautam Srinivasan (Srinivasan.Gautam@epa.gov)

Before the United States Environmental Protection Agency

In re: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)	)))))	EPA Docket No. EPA–HQ–OAR–2021–0668 FRL–8670–02–OAR

Petition for Reconsideration and for Stay of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards

ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively "Petitioners") respectfully request that the United States Environmental Protection Agency ("EPA") reconsider and stay the portion of its final rule Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) (the "FIP") that imposes a federal implementation plan on Minnesota for interstate transport of ozone under "prong 2" of Clean Air Act ("CAA") § 110(a)(2)(D)(i)(I), 42 U.S.C. § 7410(a)(2)(D)(i)(I) (the "Good Neighbor Requirements").

Circumstances arising after the close of the public comment period and before the time for judicial review demonstrate that the FIP must be withdrawn. As a result, EPA is required to grant reconsideration and reevaluate both its authority to promulgate the FIP and the propriety of applying the FIP to Minnesota.

First, EPA no longer has authority to promulgate the FIP for Minnesota based on a stay of EPA's disapproval of "prong 2" of Minnesota's State Implementation Plan ("SIP").[1] Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023) (the "SIP Disapproval"). Without the SIP Disapproval, EPA's FIP for Minnesota is *ultra vires*. Even in the absence of a judicial stay, however, EPA should reconsider and withdraw the FIP as to Minnesota because Minnesota submitted a timely and approvable SIP. EPA therefore had a nondiscretionary duty to approve it.

Second, the FIP must be reconsidered because the facts on which the FIP was based have been dramatically altered by the stay of EPA's disapproval of SIPs for Minnesota and several other states. For electric generating units ("EGUs") in particular, the viability of a robust trading program that will ensure reasonable costs of compliance and adequate protection of grid reliability can no longer be supported.

Third, EPA's provision of the modeling on which it relied for the FIP after the close of the public comment period has revealed substantial technical errors that, once corrected, support the

[1] EPA has divided the Good Neighbor Requirements set out in Clean Air Act ("CAA") § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D), into two "prongs." The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2."

conclusion that Minnesota should not be subject to the FIP. Several of these issues were detailed in Petitioners' prior Petition for Reconsideration and Stay of the SIP Disapproval ("SIP Petition"), which Petitioners incorporate here by reference and attach as Attachment A. But additional flaws have been identified in light of additional modeling EPA provided only with the FIP.

Finally, the new modeling results EPA released with its FIP establish that the FIP over-controls emissions from Minnesota and is therefore without statutory authority.

Because after-arising circumstances show that the FIP should not, and indeed could not, have been promulgated for Minnesota, Petitioners request that EPA grant reconsideration and withdraw the FIP as to Minnesota.

Further, to avoid irreparable injury, Petitioners request that EPA stay the FIP pending reconsideration and pending judicial review.

I. Background

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 ppb. This created a requirement under the Clean Air Act for states to submit revised SIPs to EPA by October 1, 2018. *See* 42 U.S.C. § 7410(a)(1). SIPs were required to meet the applicable requirements of Clean Air Act, 42 U.S.C. § 7410(a)(2), including the obligations, sometimes referred to as "Good Neighbor" obligations, to:

> (D) Contain adequate provisions—
>
> > (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—
> >
> > > (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard….[2]

The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2," of the Good Neighbor obligation. EPA concluded that Minnesota complies with prong 1 as it does not contribute significantly to nonattainment in any other State. Minnesota is implicated in the FIP only due to EPA's conclusion that it interferes with maintenance under prong 2 at a single monitor location in Cook County, Illinois.

While EPA has never promulgated regulations imposing more specific interstate transport requirements than what is contained in the statutory text, EPA has developed a 4-step framework that it used to develop the FIP:

[2] 42 U.S.C. § 7410(a)(2)(D).

(1) Identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (i.e., nonattainment and/or maintenance receptors);

(2) identify states that impact those air quality problems in other (i.e., downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis;

(3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and

(4) adopt permanent and enforceable measures needed to achieve those emissions reductions.[3]

While this framework is not binding on States, Minnesota applied it to develop its SIP.[4] In doing so, Minnesota used 2018 modeling that EPA had developed and submitted to States for their use in developing SIPs to identify monitoring sites projected to have problems attaining or maintaining the 2015 ozone NAAQS in 2023.[5] Minnesota also supplemented this modeling with modeling developed by the Lake Michigan Air Directors Consortium ("LADCO").[6] Both models showed that Minnesota contributed less than 1 percent of the NAAQS to all downwind receptors, with a highest receptor contribution from either model of 0.45 ppb.[7] Thus, following EPA's 4-factor framework, and using EPA's own modeling, Minnesota demonstrated that it was not contributing significantly to, or interfering with maintenance of, the 2015 ozone NAAQS in any downwind state.

Notably, Minnesota took a conservative approach in reaching this conclusion. In three guidance memoranda, EPA identified multiple areas where States could exercise flexibility in developing their SIPs, including in the Transport Memo itself, a separate memorandum published later that year supporting a threshold higher than 1% for determining significant contributions and interference with maintenance at step 2,[8] and a memorandum published after the SIP submission

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[3] FIP at 36,659.
[4] Minnesota's 110(a)(1) and 110(a)(2) "Infrastructure" State Implementation Plan requirements for the National Ambient Air Quality Standards for Ozone, Promulgated in 2015, EPA-R05-OAR-2022-0006-0005, at 5 (October 1, 2018) ("2018 SIP") (attached as Attachment B).
[5] 2018 SIP at 5-9; Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf at 2-3 (March 27, 2018) ("Transport Memo").
[6] 2018 SIP at 8-9.
[7] *Id.*
[8] Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, https://www.epa.gov/sites/default/files/2018-09/documents/contrib_thresholds_transport_sip_subm_2015_ozone_memo_08_31_18.pdf (Aug. 31, 2018) ("Threshold Memo").

deadline identifying flexibilities States could use in identifying maintenance-only monitors.[9] Minnesota's SIP submission demonstrated that Minnesota had met its Good Neighbor requirements even without exercising any of these flexibilities.[10] In other words, while Minnesota was not required to, it followed EPA's own framework and did not rely on additional flexibilities to demonstrate that it had satisfied its Good Neighbor obligations.[11]

This alone would have been sufficient to satisfy Minnesota's Good Neighbor obligation. Minnesota also, however, included in its SIP submission a "step 3" analysis demonstrating that Minnesota emissions of ozone precursors had been reduced from 2002 through 2015 and would be further reduced by emission limitations and reductions required by other programs.[12] Under this step 3 analysis, Minnesota demonstrated that, even if the state were having more than an insignificant impact on downwind receptors (as EPA now asserts), Minnesota's existing glidepath of emissions reductions still supported a finding that no further emission control measures would be needed to address this impact. EPA did not meet its obligation to approve or deny Minnesota's complete and approvable SIP within 12 months of submittal.

Approximately three years after EPA's deadline to approve the Minnesota SIP, EPA proposed to disapprove Minnesota's SIP on February 22, 2022, along with SIPs from 18 other states.[13] EPA did not identify a technical error in Minnesota's submission or any inconsistency with the Good Neighbor requirements, or even EPA's own framework. In fact, EPA recognized that "the modeling the MPCA used relied on the most recently available EPA modeling at the time the state submitted its SIP submittal."[14] Nonetheless, EPA proposed to reject Minnesota's SIP because EPA chose to rely "on the Agency's most recently available modeling, which uses a more recent base year and more up-to-date emissions inventories, to identify upwind contributions and 'linkages' to downwind air quality problems in 2023 using a threshold of 1 percent of the NAAQS."[15] EPA called this new modeling its "2016v2" modeling.[16] Based on this alternative modeling, EPA proposed to reject Minnesota's conclusion that it was not linked to a downwind

[9] Consideration for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, https://www.epa.gov/sites/default/files/2018-10/documents/maintenance_receptors_flexibility_memo.pdf at 3 (Oct. 19, 2018) ("Maintenance Memo").
[10] 2018 SIP at 6.
[11] Minnesota, of course, could have taken a different approach, and might have used some of these flexibilities, had EPA indicated during the statutory review period that it was considering disapproving prong 2 of Minnesota's SIP.
[12] 2018 SIP at 9-12; *see also id.* at 13.
[13] Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9,838, 9,868 (February 22, 2022) ("Proposed SIP Disapproval Rule").
[14] *Id.* at 9,867.
[15] *Id.*
[16] *Id.*

receptor, and to find instead that Minnesota was linked to two maintenance monitors in Cook County, Illinois, one with a maximum contribution of 0.97 ppb and the other 0.79 ppb.[17]

Less than two months after proposing to disapprove Minnesota's SIP, EPA proposed its own FIP for Minnesota along with 25 other states.[18] EPA used the same 2016v2 modeling as the basis for its FIP.[19] Relying on this modeling, EPA proposed to find that Minnesota "is significantly contributing to downwind nonattainment or interfering with maintenance of the 2015 ozone NAAQS in other states, based on projected nitrogen oxides (NO_x) emissions in the 2023 ozone season."[20]

On February 13, 2023, EPA published the SIP Disapproval. In its final rule, EPA approved Minnesota's SIP as to "prong 1" but disapproved Minnesota's SIP as to "prong 2."[21] Rather than use the emissions data and modeling available to Minnesota in 2018, or even emissions data and modeling available at the time of the proposed SIP disapproval, EPA made a number of additional updates to its emissions inventories and model design to construct a new 2016v3 emissions platform, which it used to generate new air quality modeling without seeking public comment to allow affected party input to help the agency assess the accuracy of the new information utilized in the modeling.[22] Minnesota was now no longer linked to two downwind receptors. It was now linked to only a single maintenance-only receptor, at a maximum contribution of 0.85 ppb for 2023.[23] While EPA also conducted updated modeling for 2026, it did not release this information in the docket for the SIP Disapproval, stating it was "not applicable" and "not used in this final action."[24]

Only a month later, the Administrator signed the FIP and EPA made the full modeling results for the 2016v3 platform available to the public.[25] Based on EPA's modeling for 2026, Minnesota is not linked to any downwind nonattainment or maintenance-only receptor in its base case modeling, with the largest contribution to downwind nonattainment or maintenance-only receptors being 0.32 ppb.[26] In fact, the sole maintenance-only receptor Minnesota was linked to in 2023 in EPA's 2016v3 modeling is modeled in attainment in EPA's 2026 modeling.[27] Notably, this modeling assumes no installation of additional pollution controls in Minnesota. Indeed, the

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[17] *Id.* at 9,868.
[18] Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard ("Proposed FIP"), 87 Fed. Reg. 20,036 (April 6, 2022).
[19] *Id*. at 20,082.
[20] *Id*. at 20,038 and 20,071-73.
[21] *See S*IP Disapproval at 9,357.
[22] *See id.* at 9,339.
[23] *Id.* at 9,357.
[24] *Id.* at 9,344, n.49.
[25] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.
[26] FIP at 36,710, Table IV.F–2; *see also id.* at 36,660 (finding Minnesota will not "continue to contribute above the 1 percent of the NAAQS threshold to at least one receptor whose nonattainment and maintenance concerns persist through the 2026 ozone season").
[27] *Id.* at 36,743, Table V.D.1–2.

only emissions reductions included from Good Neighbor obligations in EPA's modeling are an annual reduction of 139 tons NOx from emissions control optimization at EGUs.[28]

Despite the minimal connection of a single maintenance-only receptor that is modeled to be in attainment by 2026 without any FIP-based reductions from Minnesota, the FIP concludes that Minnesota "is significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in downwind states, based on projected ozone precursor emissions in the 2023 ozone season." FIP at 36,656. As a result, the FIP requires Minnesota to participate for the first time in EPA's revised version of the Cross-State Air Pollution Rule ("CSAPR") NO_x Ozone Season Group 3 Trading Program beginning in the 2023 ozone seas. *Id.* at 36,657-58.

At Step 3 of its framework, EPA did not separately analyze States significantly contributing to nonattainment versus interfering with maintenance. As a result, EPA determined that all States, regardless of their downwind impact, would be required to implement "emissions reductions commensurate with the full operation of all existing post-combustion controls (both SCRs and SNCRs) and state-of-the-art combustion control upgrades." *Id.* at 36,660. The result is that Minnesota is subject to the same "Group 3 trading program budget-setting methodology," the same "preset ozone season NOx emissions budgets for each ozone season from 2023 through 2029," and the same "enhancements," such as dynamic budget setting, recalibration of banked allowances, and backstop daily emissions rate as States significantly contributing to nonattainment. *Id.* at 36,662-63.[29]

Several Petitioners petitioned for judicial review of the SIP Disapproval in *ALLETE v. EPA*, Case No. 23-1776 (8th Cir.), and moved to stay the SIP Disapproval pending judicial review. The motion was granted and the Eighth Circuit stayed the SIP Disapproval on July 5, 2023.[30] Petitioners understand from conversations with the United States Department of Justice ("DOJ") that EPA considers the FIP inapplicable to Minnesota while the stay is in place. And indeed EPA has acknowledged that a stay of the FIP is necessary to comply with court-ordered stays of other SIP disapprovals. *See* Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 Fed. Reg. 49,295 (July 31, 2023) ("Interim Final Rule"). To date, however, EPA has taken no regulatory action to withdraw or stay the FIP for Minnesota. Action has been taken only in the form of an interim final rule for the States of Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas. *Id.*

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[28] Compare *id.* at 36,737, Table V.C.1-1; 36,738, Table V.C.1-2; and 36,785-86, Table VI.B.4.c-1.

[29] Minnesota's EGU budgets for 2026 and beyond do not reflect additional emission reductions achievable after 2026 and Minnesota is not subject to non-EGU requirements applicable to other states starting in 2026. *Id.* at 36,660 and 36,691, n.117. These differences from most States are due to Minnesota not being linked to any nonattainment or maintenance-only receptor as of 2026, not to EPA giving independent significance state as a maintenance-only State or its limited impact on only a single maintenance-only receptor before 2026.

[30] Order ("Stay Order"), *ALLETE, Inc. v. EPA*, Case No. 23-1776, ECF 5292580 (8th Cir. July 5, 2023).

II. Grounds for Reconsideration of the SIP Disapproval

Under the Clean Air Act, reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[31] Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020). Under the Administrative Procedure Act ("APA"), EPA has "broad discretion to reconsider" its regulatory actions "at any time." *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).[32]

Significant developments since the close of the of the public comment period on the FIP require reconsideration. First, due to the after-arising Stay Order, EPA does not have authority to promulgate the FIP for Minnesota. It therefore must be withdrawn. Notably, even without the Stay Order, EPA's modeling results, released without opportunity for public comment, confirm that Minnesota's SIP submission was approvable at the time it was submitted, underscoring that EPA should not have issued the FIP for Minnesota and should now withdraw it. Second, the after-arising Stay Order, combined with similar stays of SIP disapprovals issued by courts for nine other States, undermines the factual foundation on which EPA constructed the FIP and renders the FIP no longer tenable. Third, the FIP is not a logical outgrowth of the Proposed FIP. EPA's modeling platform changed significantly, as did the modeling results for Minnesota. The result is a FIP for which Petitioners did not have notice or an opportunity to comment. Because EPA did not have the benefit of notice and comment on its 2016v3 modeling, EPA was also unable to address significant errors in its modeling platform prior to finalization of the FIP that undermine its conclusion that Minnesota should be subject to the FIP. Finally, in light of EPA's new modeling, the FIP clearly overcontrols NO_x emissions from Minnesota, which is prohibited by the Supreme Court's interpretation of the Clean Air Act. *EPA v. EME Homer City Generation, L.P.* 572 U.S. 489, 523 (2014) ("EPA has a statutory duty to avoid over-control").

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[31] 42 U.S.C. § 7607(d)(7)(B).

[32] *See also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.")

A. EPA Does Not Have Authority to Promulgate the FIP for Minnesota.

1. The Stay Order Renders the FIP Ultra Vires as to Minnesota.

Minnesota submitted an approvable SIP in 2018. In February 2023, EPA approved "prong 1" of Minnesota's SIP based on EPA's finding that Minnesota does not contribute significantly to nonattainment in any downwind state. EPA disapproved Minnesota's SIP as to "prong 2," finding that Minnesota was linked to interference with maintenance of a single downwind maintenance-only receptor. SIP Disapproval at 9,357. That action, however, was challenged by several Petitioners and the Eighth Circuit has stayed the disapproval of Minnesota's SIP pending judicial review. Stay Order.

The Stay Order was issued July 5, 2023, "after the period for public comment (but within the time specified for judicial review)." 42 U.S.C. § 7607(d)(7)(B). It is also of central relevance to the FIP. The Clean Air Act requires EPA to first disapprove a SIP, or find that the States has failed to submit a SIP, before EPA can promulgate a FIP. 42 U.S.C. § 7410(c)(1). EPA has acknowledged already that the stay of similar SIP disapprovals for other States deprives it of authority to issue the FIP for those States. Interim Final Rule ("EPA must act to ensure that the Good Neighbor Plan's requirements…in each of the states for which a stay order has been issued will not take effect while the stay of the SIP Disapproval action as to that state remains in place."). The Stay Order therefore renders the FIP for Minnesota *ultra vires.* 42 U.S.C. § 7607(d)(9); *Bowen v. Georgetown Univ. Hospital*, 488 U.S. 204, 208 (1988) ("It is axiomatic that an administrative agency's power to promulgate legislative regulations is limited to the authority delegated by Congress."); *U.S. ex rel. O'Keefe v. McDonnell Douglas Corp.*, 132 F.3d 1252, 1257 (8th Cir. 1998) ("An agency's promulgation of rules without valid statutory authority implicates core notions of the separation of powers, and we are required by Congress to set these regulations aside.").

On reconsideration, EPA should withdraw the FIP for Minnesota. While EPA has, as of the date of this submission, taken no official action on the FIP for Minnesota, EPA has begun to act with respect to several states for which similar judicial stays have been issued. Interim Final Rule at 49,295 (taking action with respect to "Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas only"). Petitioners note that, in acting with respect to Minnesota, action identical to EPA's Interim Final Rule would be insufficient. The Interim Final Rule issues a "stay [that] is limited to requirements for which the EPA does not currently have authority to implement…pending judicial review." *Id*. This is insufficient for two reasons. First, the Clean Air Act requires EPA to disapprove the State's SIP before it can "*promulgate* a Federal implementation plan." 42 U.S.C. § 7410(c)(1) (emphasis added). EPA cannot promulgate, and then stay, the FIP. It must withdraw it. *See Union Pacific Railroad Co. v. Dept. of Homeland Security*, 738 F.3d 885, 900 (8th Cir. 2013) (agency action that is "'unlawful'…must be 'set aside'") (quoting 5 U.S.C. § 706(2).

Second, merely staying the FIP will not fulfill the requirements of the Stay Order. A stay pending judicial review is issued to preserve the *status quo* and prevent the incurrence of imminent and irreparable harm pending judicial review. *See Nken v. Holder*, 556 U.S. 418, 426 (2009). The Interim Final Rule stays the effective date of the FIP but it makes no provision for modifying the deadlines in the FIP that will apply if the FIP is not vacated after the stay is lifted. As a result, even as modified by the Interim Final Rule, there is no provision in the FIP to extend deadlines applicable to Minnesota when the stay is lifted to allow the time needed to come into compliance. The result is that Petitioners must either trust EPA enforcement discretion and equitable relief, or be prepared to participate in the Group 3 trading program on a moment's notice.

To mitigate this risk, Petitioners will need to take many of the same actions that they would have been required to take had the FIP not been stayed (which again EPA has not done for Minnesota). This would not effectuate the stay order issued by the Eight Circuit. EPA must reconsider its FIP and withdraw it or, at a minimum, both stay the effective date of the FIP as to Minnesota and extend all applicable deadlines for the duration of the stay.

2. EPA Has a Nondiscretionary Duty to Approve Minnesota's SIP

Even absent a judicial stay of the SIP Disapproval, EPA should reconsider and withdraw the FIP as to Minnesota because Minnesota submitted a timely and approvable SIP. As discussed in Petitioners' SIP Petition, which is attached hereto and incorporated by reference, Minnesota timely submitted a SIP that meets the requirements of the Clean Air Act. As a result, EPA has a nondiscretionary duty to approve Minnesota's SIP.

While EPA conducted modeling after the SIP submission deadline that EPA believes brings into question the adequacy of Minnesota's SIP, this does not give EPA the authority to disapprove Minnesota's SIP. The Clean Air Act sets forth specific procedures for addressing information that arises after an approvable SIP is submitted, and none involve disapproval of a pending SIP submission. Further, EPA has not attempted to use any of these procedures to address the after-arising 2016v3 modeling.

Further, while it was improper for EPA to use the SIP approval process to introduce its 2016v3 modeling, as discussed in the attached SIP Petition, the 2016v3 modeling has data errors for Minnesota emission units and significant bias at the key modeling receptor at which EPA found a purported link to Minnesota. Correcting this bias alone would demonstrate even under the 2016v3 modeling that Minnesota has no link to a downwind nonattainment or maintenance-only receptor and that the conclusions in Minnesota's 2018 SIP are still correct.

B. The Factual Predicate for the FIP is No Longer Supportable.

In addition to the Stay Order, SIP disapprovals for nine other States have been stayed as of the filing of this petition after the close of the public comment period but before the time for judicial review: Arkansas, Kentucky, Louisiana, Mississippi, Missouri, Nevada, Oklahoma, Texas, and Utah.[33] Additional motions to stay are pending.[34] As discussed above, since these SIP disapprovals were EPA's legal prerequisite for promulgation of the FIP, EPA has already recognized that it now lacks authority to apply the FIP to these States pending judicial review. Moreover, because a stay is predicated on a finding a likelihood of success on the merits, there is a substantial likelihood that the FIP will never apply to most or all of these States. *See Nken*, 556 U.S. at 434.

These States represent a large portion of the emission allowances that EPA assumed would be available for trading in the Group 3 trading program, both to maintain a reasonable cost of compliance and to ensure adequate grid reliability. *See* FIP at 36,766, n.295 (the "trading program…depend[s] on the existence of a marketplace for purchasing and selling allowances"); *id.* at 36,789 (noting the importance of "allowance market liquidity" especially during the 2024-2029 period); *id.* at 36,774 (citing "the use of a trading program as the mechanism for achieving…emissions reductions" as a factor in finding no "material risk of adverse impact to electric system reliability" and as the reason why additional accommodation for "reliability-related need" was unnecessary). The emissions reductions from these States were also a significant factor in the policy cases used by EPA for its IPM modeling with Steps 1 and 2 and its AQAT modeling for Steps 3 and 4. Accordingly, the legal and factual basis for the FIP has so fundamentally changed that the FIP can no longer stand on the current administrative record.

EPA must therefore reconsider the FIP and determine whether, in light of the inapplicability of the FIP for the above states pending judicial review (which may extend into the 2024 ozone trading season) and likely permanently, requires modification or withdrawal of the FIP for those remaining States, as well as the above States.

C. The FIP is Based on Evidence that was Not Subject to Notice and Comment.

1. The FIP Relies on Modeling That was Not Publicly Available until EPA Signed the FIP.

The proposed FIP was based on modelling that EPA refers to as its "2016v2" modeling. *See* FIP at 36,673. The public comment period closed in June 2022 without any change in EPA's modeling, but EPA did not rely on the 2016v2 results for the FIP. Instead, EPA "revised its 2016v2 modeling platform and input since the platform was made available for comment" to create the 2016v3 modeling. *Id.* at 36,674. It then "reassessed" its modeling results "to inform the final

[33] *See* Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1 (May 1, 2023) (staying Texas and Louisiana SIP disapprovals); *Arkansas v. EPA*, Case No. 23-1320, ECF 5280996 (May 25, 2023) (staying Arkansas SIP disapproval); Order, *Missouri v. EPA*, Case No. 23-1719, ECF 5281126 (May 26, 2023) (staying Missouri SIP disapproval); Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 359-2 (June 8, 2023) (staying Mississippi SIP disapproval); *Nevada Cement Co. v. EPA*, Case No. 23-682, ECF 27.1 (July 3, 2023) (staying Nevada SIP disapproval); Order, *Kentucky v. EPA*, Case No. 23-3216, ECF 39-2 (July 25, 2023) (staying Kentucky SIP disapproval); Order, *Utah v. EPA*, Case No. 23-9509, ECF 010110895101 (July 27, 2023) (staying Oklahoma and Utah SIP disapprovals).

[34] *See Ohio v. EPA*, Case No. 23-1183 (D.C. Cir); *West Virginia v. EPA*, Case No. 23-1418 (4th Cir.); *Alabama v. EPA*, Case No. 23-11196 (11th Cir.).

action." *Id.* These were not minor amendments. EPA "evaluated a raft of technical information and critiques of its 2016v2 modeling" and "incorporated updates into the version of the modeling used to support this final rule (2016v3)." *Id.* Further, while EPA released some of its 2016v3 results with the SIP Disapproval in February 2023, it withheld the results for model year 2026, asserting that these results were "not applicable and were not used in this final action." SIP Disapproval at 9,344, n.30. As a result, EPA did not release the full modeling results on which the FIP is based until it signed the FIP in March 2023.

This was "highly improper." *Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 540 (D.C. Cir. 1983); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations). EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id.* at 540. If "documents of central importance upon which EPA intended to rely ha[ve] been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 [are] violated." *Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981).

EPA's late addition of modeling central to its FIP alone justifies reconsideration.

2. The FIP Omitted Public Comment on Critical Modeling Inputs, Leaving Reconsideration the Only Option for Correcting Material Errors.

Because EPA did not submit its 2016v3 modeling to notice and comment, EPA could not benefit from public review of EPA's emissions data and model results. The new emissions inventory and modeling platform are of central relevance to EPA's rule. EPA identifies the 2016v3 platform as "the version of the modeling used to support this final rule." FIP at 36,674. Further, while the FIP asserts that its "modeling on the whole has provided consistent outcomes regarding which states are linked to downwind air quality problems," EPA acknowledges this is not the case for Minnesota, which "went from being unlinked to being linked in 2023 between the 2011-based modeling provided in the March 2018 memorandum and the 2016v3-based modeling." *Id.* Moreover, while this linkage is present in both the 2016v2 and 2016v3 modeling, it is far more attenuated in the 2016v3 modeling, which identifies only a single maintenance-only receptor, to which Minnesota is "linked" by a maximum modeled contribution of 0.85 ppb. *See id.* at 36,710, Table IV.F–1.

While there have been errors in each of EPA's modeling at each stage of the regulatory process, the errors in the 2016v3 emissions inventory and modeling arose only with the publication of the final SIP Disapproval and FIP. As a result, errors in EPA's 2016v3 modeling could not have been submitted to EPA during the public comment period for the FIP, which closed in June 2022.

In their SIP Petition, Petitioners identified material errors in the limited time Petitioners had to review the 2016v3 data prior to the time for judicial review. SIP Petition at 8-10. This included significant errors in EPA's estimate of NOx emissions for 2023, such as EPA's addition of 2,822 tons of NOx for Northshore Mining Co. – Silver Bay power for boilers that have been idled since October 2019 and are expected to have zero emissions in 2023. *Id.* at 8. It also included identification of significant bias in the majority of modeled days used to establish a link to Minnesota. *Id.* at 9-10. These errors were obviously not corrected before EPA relied on the same modeling to support the FIP, since the Administrator had already signed the FIP a month earlier. They are, however, centrally relevant to EPA's determination that Minnesota should be subject to the FIP. As addressed in the SIP Petition, correcting bias outside EPA guidelines alone would likely result in Minnesota no longer being linked to any downwind maintenance-only receptors. *Id.* at 10.

Since the submission of the SIP Petition, Petitioners have identified additional discrepancies in EPA's air quality modeling. As discussed in the attached Report of Alpine Geophysics, Attachment C ("Report"), EPA failed to appropriately estimate 2023 base case emissions for multiple upwind EGU sources using IPM, thereby compromising the modeled downwind ozone concentrations, associated downwind monitor nonattainment designations, and the resulting significant contribution calculations on which EPA relied, not just for Minnesota, but for every state with a modeled contribution to the Alsip/Village Garage receptor (the sole receptor creating a "link" to Minnesota in the FIP). Report at 51. If EPA had properly characterized emissions from these States using historical operation trends (as it did in the Step 3 process), the Alsip/Village Garage receptor may have been modeled in attainment, not as a maintenance receptor, removing Minnesota from the FIP at Step 2. *Id.*

Given the above considerations and Minnesota's unique circumstances, EPA should grant reconsideration to reassess Minnesota's impact on downwind maintenance of attainment to determine whether further emission reductions in a FIP are needed for Minnesota to satisfy its prong 2 Good Neighbor obligations.

D. The FIP Overcontrols Emissions from Minnesota.

The Supreme Court has made clear that EPA cannot implement a FIP that "over-controls" emissions by requiring "reductions unnecessary to downwind attainment *anywhere.*" *EME Homer City*, 572 U.S. at 522 (emphasis in original). In particular, courts will find over-control "when those downwind locations [to which a State has been linked] would achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations." *EME Homer City Generation, L.P. v. EPA*, 795 F.3d 118, 127 (D.C. Cir. 2015). Similarly, the Supreme Court has noted that "EPA is limited, by the second part of the [Good Neighbor] provision, to reduce only by 'amounts' that 'interfere with *maintenance*,' i.e., by just enough to permit an already-attaining State to maintain satisfactory air quality." *EME Homer City*, 572 U.S. at 515, n.18 (quoting 42 U.S.C. § 7410) (emphasis in original); *see also EME Homer City*, 795 F.3d at 127, n.4 ("The Supreme Court held that the same was true for upwind States that 'interfere with maintenance' at downwind locations.").

EPA acknowledged that Minnesota is not significantly interfering with attainment of the NAAQS in any downwind State when it approved prong 1 of Minnesota's SIP. SIP Disapproval at 9,357. Thus, the "reductions" the FIP imposes on Minnesota are "unnecessary to downwind attainment anywhere." *EME Homer*, 572 U.S. at 522. EPA concluded in the FIP that Minnesota should nonetheless be subject to the FIP because of a single modeled maintenance-only receptor to which EPA determined that Minnesota has a maximum impact of 0.85 ppb in 2023. *See* FIP at 36,710, Table IV.F–1.

EPA's own 2016v3 modeling for 2026, however, shows that this same receptor will be in full attainment by 2026 with no reductions from Minnesota other than already "on the books" rules and regulations.[35] In other words, EPA's 2026 modeling establishes that the sole receptor linking Minnesota in the FIP "will achieve attainment even if less stringent emissions limits were imposed on the upwind States linked to those locations." *EME Homer City*, 795 F.3d at 127. Indeed, it will achieve attainment even if *no* emission limits are imposed in the FIP. This is the definition of over-control.

EPA also cannot reasonably assert that Minnesota should be subject to the FIP to prevent interference with maintenance before 2026. First, even in the two ozone seasons (at most) that the FIP would apply to Minnesota, EPA's modeling projects an impact on the Alsip/Village Garage monitor of approximately 0.0010 ppb.[36] This *de minimis* contribution cannot be said to be necessary to eliminate to "permit an already-attaining State to maintain satisfactory air quality." *EME Homer City*, 795 F.3d at 127, n.4. Second, even if this were the case, it would not justify continued application of the FIP to Minnesota in 2026 and beyond, as the FIP does.

EPA's modeling results were not made publicly available until 2023. As a result, they clearly arose "after the period for public comment (but within the time specified for judicial review)." 42 U.S.C. § 7607(b)(1). They are also of central relevance to the FIP as applied to Minnesota. As the Supreme Court has made clear, a FIP that results in over-control is "outside the Agency's statutory authority." *EME Homer City*, 572 U.S. at 522. EPA must therefore grant reconsideration and modify the FIP as to Minnesota to eliminate over-control. Moreover, because EPA's own modeling shows that no emission reductions from Minnesota are needed for attainment of the NAAQS in every downwind State, EPA should find on reconsideration that no emission reductions are needed from Minnesota to satisfy the State's Good Neighbor obligations.

III. Grounds for Stay of the FIP.

EPA has authority to stay the FIP both pending reconsideration and pending judicial review. First, a stay pending reconsideration can be granted for three months. 42 U.S.C. § 7607(d)(7). Second, EPA has authority under the APA to stay the FIP pending judicial review.

A. A Stay Pending Reconsideration is Appropriate.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the

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[35] *See* Air Quality Modeling Final Rule Technical Support Document, https://www.epa.gov/system/files/documents/2023-03/AQ%20Modeling%20Final%20Rule%20TSD.pdf at 17, Table 3-5 (showing Monitor 170310001 no longer listed as a monitor-only receptor in the 2026 base case).

[36] *S*ee Ozone AQAT Final, EPA-HQ-OAR-2021-0668-1116 (comparing 2023 Base Case tab [2023_step3_base; value 0.850667659939893 ppb] with SCR/SNCR Optimization tab [2023_step3_SNCRopt; value 0.849648804871336 ppb]).

court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). A stay pending reconsideration is justified here.

As discussed above, the FIP was not legally promulgated for Minnesota and cannot now be enforced.

Further, EPA issued a final rule based primarily on emissions data and modeling that it did not make publicly available before issuance of the final rule. Even upon publication, EPA's release of data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the data and checking its accuracy has taken several weeks. It would take many more weeks to rerun EPA's modeling to confirm the results in the FIP and identify additional areas of concern to those raised in this Petition.

EPA will also likely need time to evaluate the errors Petitioners have identified already and discussed above. This modeling will likely require several weeks and, given the likelihood that it will result in withdrawal or modification of the FIP as to Minnesota, should be evaluated before the FIP is made applicable to Minnesota.

A stay will also not unduly impact downwind states. The FIP cannot be enforced in Minnesota during the pendency of the current SIP Disapproval litigation, which will likely not be resolved for the duration of a reconsideration stay, which is limited to three months. Moreover, Minnesota is not modeled to contribute to nonattainment in any downwind state, and under EPA's most recent modeling, Minnesota is linked only to a single maintenance-only receptor for which EPA's own modeling shows the receptor will be in full attainment by 2026 without any reductions from Minnesota. As a result, a stay pending reconsideration will have no impact on downwind attainment or maintenance of the NAAQS.

B. EPA Should Stay the Effective Date of the FIP Pending Judicial Review.

Under the APA, EPA may stay the effective date of the FIP pending judicial review when "justice so requires." 5 U.S.C. §705. Multiple petitions have already been filed for judicial review, including petitions by Texas, Utah, Ohio, Indiana, West Virginia, and Oklahoma. More are likely, including a petition for judicial review of EPA's FIP for Minnesota, which is being filed contemporaneously with this Petition. These cases are already spread across three circuits, and additional litigation may expand the number of courts further.

The effective date of the FIP is August 4, 2023, but the FIP already cannot be applied in several states, including Minnesota, because of stays of the SIP Disapprovals required to authorize promulgation of the FIP. A stay pending judicial review will simply reflect the legal reality that is already mandated by stays of EPA's SIP Disapproval. Further, the significant legal flaws in EPA's FIP discussed above, coupled with the technical and legal concerns it raises, make it likely that judicial review will result in a remand if not vacatur of the FIP. As a result, to avoid the unnecessary expenditure of EPA resources on a FIP, state resources on FIP implementation, and the resources of the public and regulatory industries in addressing a FIP that is likely to not be required, justice requires that the FIP be stayed pending judicial review.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors indicate support for EPA in granting a stay of the FIP. Under this standard, the considerations for a stay are:

1. whether the stay applicant has made a strong showing that he is likely to succeed on the merits;
2. whether the applicant will be irreparably injured absent a stay;
3. whether issuance of the stay will substantially injure the other parties interested in the proceeding; and
4. where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

1. Petitioners Have Made a Strong Showing They Are Likely to Succeed on the Merits

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id. (quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the FIP has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's FIP for Minnesota is *ultra vires*, was based on an incorrect set of emissions data, biased modeling results, and overestimation of emissions that, when adjusted, support the conclusion that Minnesota's is not contributing to nonattainment or interfering with maintenance in any downwind state and does not need to impose additional emission reductions to satisfy its Good Neighbor obligations. Procedurally, EPA did not provide notice and comment on modeling that is central to EPA's decision to impose a FIP on Minnesota and to the level of stringency the FIP can reflect without constituting over-control. In doing so, EPA deprived Petitioners of their statutorily-guaranteed right to participate in the rulemaking process.

More generally, the FIP does not reflect the cooperative federalism required by the Clean Air Act. As EPA has previously acknowledged, "[t]he CAA establishes a framework for state-Federal partnership to implement the NAAQS based on 'cooperative federalism.'" SIP Disapproval at 9,367. Under this model, "the Federal Government establishes broad standards or goals, states are given the opportunity to determine how they wish to achieve those goals, and if states choose not to or fail to adequately implement programs to achieve those goals, a Federal agency is empowered to directly regulate to achieve the necessary ends." *Id.* Thus, "states have the obligation and opportunity in the first instance to develop an implementation plan to achieve the NAAQS under CAA section 110" and "EPA will approve SIP submissions under CAA section 110 that fully satisfy the requirements of the CAA." *Id.*

Under this framework, EPA is given two years following disapproval of a SIP to promulgate a FIP. 42 U.S.C. § 7410(c)(1). While the Supreme Court has stated that "EPA is not obliged to wait two years or postpone its action even a single day" after disapproving a SIP,[37] this should not be read as a license to run roughshod over State attempts to fulfill their primary role under the Clean Air Act. EPA must still interpret its obligations under the Clean Air Act "with a view to their place in the overall statutory scheme," and cannot act in a manner that is "'incompatible with 'the substance of Congress' regulatory scheme.'" *UARG v. EPA*, 573 U.S. 302, __ (2014) (*quoting FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 and 156 (2000)). Here, EPA departed from Congress' regulatory scheme when it proposed a FIP just one month after *proposing* to disapprove Minnesota's SIP and the Administrator signed the FIP just one month after finalization of the SIP Disapproval, despite Minnesota having timely submitted a complete SIP that meets all requirements of the Clean Air Act.

Because EPA's FIP is *ultra vires*, over-controls emissions from Minnesota, was procedurally improper, and undermines the core cooperative federalism embodied in CAA § 110, Petitioners are likely to prevail on the merits of a judicial challenge. This further supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

2. Petitioners Will Suffer Irreparable Harm from a Denial of Stay.

Relevant factors for evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C. Cir.1985)).

The FIP poses substantial and imminent injuries to Petitioners. As discussed above, the FIP has been promulgated without statutory authority. This places the entire State of Minnesota under an *ultra vires* regulation. While EPA has made clear that it does not consider the FIP enforceable while the Stay Order is in place, this does not prevent third parties from seeking to enforce it on their own behalf. *See* 42 U.S.C. § 7604. Petitioners should not have to bear court costs seeking to defend and dismiss claims that are brough only because EPA has not withdrawn a regulation it acknowledges it was without statutory authority to promulgate, and such imminent threats of litigation are an irreparable injury. *See Newman v. Nazcr Trac Prop. Owners Ass'n, Inc.*, 601 F. Supp. 3d 357, 367 (E.D. Wis. 2022) ("the irreparable harm is traceable to Defendants because Plaintiffs are under the certain threat of enforcement").

In addition, the Stay Order says the FIP only by preventing its application in Minnesota. The Stay Order does not address the deadlines that would apply to Petitioners if it is lifted. Absent a stay of the FIP itself, or further modification of the deadlines in the FIP, Petitioners could become subject to compliance obligations without sufficient time to meet them unless they act now in preparation for compliance. Needing to comply with an invalid regulation is also an irreparable

[37] *EME Homer City*, 572 U.S. at 509.

harm. *See Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) ("complying with a regulation later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs.") (Scalia, J., concurring in part and in the judgment).

3. Staying the FIP will not Significantly Injure Other Parties.

As discussed above, emission reductions from Minnesota are not needed for any downwind state to attain the NAAQS, and they are likely not needed to prevent interference with maintenance of the NAAQS in any downwind state. Moreover, the FIP cannot be applied in Minnesota pending judicial review of the SIP Disapproval, which will likely mean that the FIP will not apply for the remainder of the 2023 ozone trading season, and possibly the start of the 2024 ozone trading season as well. As a result, a stay is unlikely to harm any third party.

4. The Public Interest Lies in Granting a Stay.

As courts have held, there is a public interest enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay. As discussed above, EPA's FIP is without statutory authority and was promulgated through the inequitable exclusion of public participation on the data central to EPA's FIP. The result will be costly public expenditures, both by Minnesota and Petitioners, to prepare for a FIP that will likely never be implemented and in any event is unnecessary.

While it was an error for EPA to promulgate the FIP, EPA can ameliorate the harm of this error by staying the effect of the FIP until the merits of the issues above can be fully evaluated and addressed.

IV. Conclusion

The State of Minnesota has expended substantial effort and resources to regulate the emission of NOx within its borders. Those efforts have successfully reduced State impacts on downwind receptors to a point that Minnesota is not a significant contributor to nonattainment or interference with maintenance of the 2015 ozone standard in any State. Based on the best available data and modeling science available at the time, Minnesota assessed its impact on downwind states, as it was required to do under the Clean Air Act, and appropriately concluded that it was not interfering with maintenance of attainment in any State. EPA should have approved that SIP. Instead, it rushed to promulgate a FIP that it now does not have authority to promulgate and that is based on factual assumptions EPA can no longer maintain. Further, in promulgating the FIP, EPA committed technical and procedural errors that undermine public participation and resulted in a FIP that exceeds EPA's authority by overcontrolling emissions from Minnesota.

Because circumstances arising after the close of the public comment period and before the time for judicial review demonstrate that the FIP must be withdrawn, EPA is obligated to grant reconsideration and should withdraw the FIP as to Minnesota in its entirety. Further, to avoid the significant and irreparable harm to Petitioners arising from EPA's erroneous promulgation of the FIP, EPA should stay the FIP as applied to Minnesota pending reconsideration and pending judicial review.

Please contact our counsel, Douglas.McWilliams@Squirepb.com, to set up a meeting to discuss reconsideration of the FIP.

Dated: August 4, 2023

Respectfully submitted,

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Attachment A

(SIP Petition)

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April 14, 2023

VIA E-MAIL AND FEDERAL EXPRESS

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1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023)

Dear Administrator Regan:

On behalf of our clients, ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively the "Minnesota Good Neighbor Coalition"), please find enclosed a petition for reconsideration and stay of the disapproval of "prong 2" of Minnesota's State Implementation Plan ("SIP") in the United States Environmental Protection Agency's final rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023).

Please contact me with any questions you may have.

Sincerely,

/s/ Douglas A. McWilliams
Douglas A. McWilliams

cc: Olivia Davidson
Debra Shore
Gautam Srinivasan
Thomas Uher

Before the United States Environmental Protection Agency

In re: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023)	))))))	EPA Docket Nos. EPA–HQ–OAR–2021–0663; EPA–R05–OAR–2022–0006; FRL–10209–01–OAR

Petition for Reconsideration and for Stay of the Air Plan Disapprovals for Interstate Transportation of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively "Petitioners") respectfully request that the United States Environmental Protection Agency ("EPA") reconsider and stay the portion of its final rule Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023) (the "SIP Disapproval") that disapproves Minnesota's state implementation plan ("SIP") for interstate transport for "prong 2" of Clean Air Act ("CAA") § 110(a)(2)(D)(i)(I), 42 U.S.C. § 7410(a)(2)(D)(i)(I).

Minnesota is uniquely situated in the SIP Disapproval. In EPA's February 13 action, Minnesota's SIP was approved for "prong 1"[1] based on EPA's finding that Minnesota does not contribute significantly to nonattainment in any downwind state. Minnesota's SIP was disapproved for "prong 2," with EPA finding that Minnesota was linked to interference with maintenance of a single downwind maintenance-only receptor. EPA has subsequently found in its promulgation of an ozone transport federal implementation plan ("FIP") that Minnesota was not linked to any downwind non-attainment or maintenance-only receptor when modeled for 2026.

Based on the best evidence available in 2018 when Minnesota submitted its SIP to EPA for approval (and on April 1, 2020 when EPA had a statutory obligation to approve or deny the Minnesota SIP), Minnesota was ***not*** linked to interference with attainment or maintenance in any downwind state. But, EPA did not timely act on the Minnesota SIP, and then it moved the goal posts. Based on new modeling and emission data EPA developed years later, (the "2016v2" modeling platform) EPA proposed to find that Minnesota was linked to two downwind maintenance-only receptors due to a modeled impact of less than 1 ppb at each receptor. In the

[1] As discussed on page 4 *infra*, EPA has divided the Good Neighbor obligation set out in Clean Air Act ("CAA") § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D), into two "prongs." The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2."

final SIP Disapproval, EPA again revised its emissions data and modeling (the "2016v3" modeling platform) and now finds that Minnesota is linked in 2023 to only a single maintenance-only monitor, at a maximum contribution of 0.85 ppb. Further, EPA has since released updated modeling results for 2026 that show that this same monitor will be in attainment without any material reduction of emissions from Minnesota. As a result, after five years of updates, EPA's modeling results support the same conclusion that Minnesota reached in 2018, namely that additional emissions reductions are not needed to prohibit emissions in Minnesota that will contribute significantly to nonattainment, or interfere with maintenance of, the 2015 8-hour ozone NAAQS in any downwind state. We ask that EPA grant this petition for reconsideration to do what it should have done in 2018—Approve the Minnesota SIP.

The approvability of Minnesota's original SIP submittal is corroborated by two additional pieces of information that were not available during the public comment period for the proposed SIP disapproval or prior to EPA's release of its 2016v3 modeling in 2023. First, EPA's 2016v3 emissions inventory materially overstates Minnesota's 2023 NOx emissions; for example, it incorrectly assumes over 2,800 tons of NOx from an electric generating facility that has been idled since 2019 and is projected to have zero emissions in 2023. By merely correcting the projected actual NOx emissions, Minnesota has already achieved more NOx reductions than EPA's FIP would require of Minnesota. This effectively confirms Minnesota's step 3[2] conclusion in its 2018 SIP that no additional permanent or enforceable measures were needed beyond those already implemented by the state.[3]

Second, as EPA has recognized, its CAMx modeling is subject to significant bias in areas of complex meteorology, including the water/land interface occurring at the sole maintenance monitor that EPA has linked to Minnesota emissions. While EPA released with the final SIP Disapproval a review of this localized bias risk for southern Lake Michigan, that review was materially flawed and does not address the significant over-prediction bias occurring on the precise days EPA selected for use in evaluating Minnesota's SIP. As a result, EPA's general conclusion that adjusting for bias will not affect the outcome of its SIP reviews, does not apply to its review of the Minnesota SIP. To the contrary, adjusting for material bias results in the sole maintenance-only monitor to which Minnesota was linked by EPA becoming an attainment monitor in 2023. In other words, eliminating high-bias days alone completely addresses EPA's objection to Minnesota's 2018 SIP and eliminates Minnesota at Step 1 of EPA's four-step analysis.

Reconsideration is appropriate to make the above corrections to the emissions inventory and to account for modeling bias. After incorporating this new material information into the SIP analysis, we believe that EPA will conclude as we have that Minnesota's original 2018 SIP determination that it is not having a downwind impact on attainment or maintenance that requires additional permanent and enforceable measures was correct and warrants approval of

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[2] *See* page 4 *infra* for the list of four steps in EPA's 4-step framework for evaluating Good Neighbor SIP submissions.

[3] *See* Minnesota's 110(a)(1) and 110(a)(2) "Infrastructure" State Implementation Plan requirements for the National Ambient Air Quality Standards for Ozone, Promulgated in 2015, EPA-R05-OAR-2022-0006-0005, at 12 (October 1, 2018) ("2018 SIP").

the Minnesota SIP. Reconsideration is also appropriate to address a significant procedural flaw in the finalization of the SIP Disapproval. Specifically, the SIP Disapproval relies on information that was not available to EPA, Minnesota, or any other interested parties until 2023, well past the period for Minnesota's SIP submission and EPA's statutory deadline to approve Minnesota's SIP. While EPA has an obligation to use the best available evidence in making its regulatory decisions, that obligation is not unbounded and cannot be used to circumvent the procedures set forth in the Clean Air Act. When Minnesota timely submitted a SIP that is approvable based on the information known at the time, EPA had an obligation to approve the SIP. The Act does not allow EPA unfettered discretion to delay approval until new information becomes available, and then move the goalposts. For States that have done their part to invest resources in developing a timely and approvable SIP, EPA has a statutory obligation to act. EPA may still consider new scientific data and modeling after the statutory deadline, but there is a separate administrative process available to EPA that respects the State's SIP process. Minnesota should have an approved SIP and EPA should be considering whether new information is sufficiently material to require a "SIP call" pursuant to CAA § 110(k)(5), 42 U.S.C. § 7410(k)(5), to give Minnesota the opportunity to revise its SIP given the new available information. Having chosen to use this new information to disapprove prong 2 of Minnesota's SIP instead, EPA deprived Petitioners, the State, and other interested parties of significant procedural protections and opportunities for public input that were required by the Clean Air Act. Granting reconsideration allows EPA the opportunity to cure the procedural flaw that its final action is based on material information that has not been subject to the notice and comment process.

Given that new information was made available after the close of the public comment period, but before the time for judicial review, that such information actually undermines EPA's basis for disapproving prong 2 of Minnesota's 2018 SIP in the SIP Disapproval, and reconsideration would address the harms caused by significant procedural defects in the SIP Disapproval, Petitioners respectfully request that EPA grant reconsideration for the purpose of reviewing this new information and approving prong 2 of Minnesota's 2018 SIP.

Further, since the disapproval of prong 2 of Minnesota's SIP, and the continued implementation of EPA's subsequently-issued FIP, will cause irreparable harm to Petitioners, we request that EPA grant a stay of the disapproval of prong 2 of Minnesota's SIP pending reconsideration and pending judicial review, which will also address the irreparable harm caused by EPA's FIP.

I. Background

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 ppb. This created a requirement under the CAA for states to submit revised SIPs to EPA by October 1, 2018.[4] SIPs were required to meet the applicable requirements of CAA § 110(a)(2), 42 U.S.C. § 7410(a)(2), including an obligation, sometimes referred to as a "Good Neighbor" obligation, that the SIPs:

[4] 42 U.S.C. § 7410(a)(1).

(D) Contain adequate provisions—

> (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—
>
> > (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, …

42 U.S.C. § 7410(a)(2)(D). The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2," of the Good Neighbor obligation.

While EPA has never promulgated regulations imposing more specific interstate transport requirements than what is contained in the statutory text, EPA has developed a 4-step framework that it stated the agency would use to evaluate a state's compliance with its Good Neighbor obligation. Namely:

(1) Identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (i.e., nonattainment and/or maintenance receptors);

(2) identify states that impact those air quality problems in other (i.e., downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis;

(3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and

(4) adopt permanent and enforceable measures needed to achieve those emissions reductions.[5]

Minnesota took a notably conservative approach in its SIP. First, in EPA's Transport Memo, EPA recognized that its four-step framework was not binding, and offered that states "have flexibility to follow this framework or develop alternative frameworks."[6] Despite this flexibility, Minnesota adopted EPA's framework for its SIP.[7] Second, EPA made clear, in the

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[5] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf at 2-3 (March 27, 2018) ("Transport Memo").

[6] *Id.*

[7] 2018 SIP at 5.

Transport Memo and in a separate memorandum published later that year, that states did not need to adopt EPA's suggested 1% threshold for determining significant contributions and interference with maintenance at step 2.[8] Here too, Minnesota did not exercise this flexibility, and chose instead to use EPA's preferred approach.[9] Third, EPA guidance offered states flexibility regarding how to determine which downwind monitors should be considered maintenance receptors.[10] Again, Minnesota followed EPA's suggested approach.[11] In other words, while Minnesota was not required to, it followed EPA's own framework and did not rely on additional flexibilities to demonstrate that it had satisfied its Good Neighbor obligations.[12]

Minnesota also used the best information available at the time to determine its Good Neighbor obligations. Specifically, Minnesota used EPA's own modeling and modeling developed by the Lake Michigan Air Directors Consortium ("LADCO") to identify monitoring sites projected to have problems attaining or maintaining the 2015 ozone NAAQS in 2023.[13] It then projected the state's own contributions to those nonattainment and maintenance monitors using both sets of results.[14] Both EPA's and LADCO's modeling showed that Minnesota would contribute less than 1 percent of the NAAQS to all downwind receptors, with a highest receptor contribution from either model of 0.45 ppb.[15] Thus, following EPA's 4-factor framework, and using EPA's own modeling and proposed threshold, Minnesota demonstrated that it was not contributing significantly to, or interfering with maintenance of, the 2015 ozone NAAQS in any downwind state.

This alone would have been sufficient to satisfy Minnesota's Good Neighbor obligation. Minnesota also, however, included in its SIP submission a "step 3" analysis demonstrating that Minnesota emissions of ozone precursors had been reduced from 2002 through 2015 and would be further reduced by emission limitations and reductions required by other programs.[16] Under this step 3 analysis, Minnesota demonstrated that, even if the state were having more than an insignificant impact on downwind receptors (as EPA now asserts), Minnesota's existing glidepath of emissions reductions still supported a finding that no further emission control measures would

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[8] Transport Memo at A-2; Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards (Aug. 31 2018) ("Threshold Memo")
[9] 2018 SIP at 6.
[10] Transport Memo at A-2; Consideration for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, https://www.epa.gov/sites/default/files/2018-10/documents/maintenance_receptors_flexibility_memo.pdf at 3 (October 19, 2018) ("Maintenance Memo")
[11] 2018 SIP at 5.
[12] Minnesota, of course, could have taken a different approach, and might have used some of these flexibilities, had EPA indicated during the statutory review period that it was considering disapproving prong 2 of Minnesota's SIP.
[13] 2018 SIP at 5-9.
[14] *Id.*
[15] *Id.* at 8-9.
[16] *Id.* at 9-12; *see also id.* at 13.

be needed to address this impact. EPA did not meet its obligation to approve or deny Minnesota's complete and approvable SIP within 12 months of submittal.

Approximately three years after EPA's deadline to approve the Minnesota SIP, EPA proposed to disapprove Minnesota's SIP on February 22, 2022, along with SIPs from 18 other states.[17] EPA did not identify a technical error in Minnesota's submission or any inconsistency with the Good Neighbor requirements, or even EPA's own framework. In fact, EPA recognized that "the modeling the MPCA used relied on the most recently available EPA modeling at the time the state submitted its SIP submittal."[18] Nonetheless, EPA proposed to reject Minnesota's SIP because EPA chose to rely "on the Agency's most recently available modeling, which uses a more recent base year and more up-to-date emissions inventories, to identify upwind contributions and 'linkages' to downwind air quality problems in 2023 using a threshold of 1 percent of the NAAQS." *Id.* Based on this data, EPA proposed to reject Minnesota's conclusion that it was not linked to a downwind receptor, and to find instead that Minnesota was linked to two maintenance monitors in Cook County, Illinois, one with a maximum contribution of 0.97 ppb and the other 0.79 ppb.[19]

On February 13, 2023, EPA published the SIP Disapproval. In its final rule, EPA approved Minnesota's SIP as to "prong 1" but disapproved Minnesota's SIP as to "prong 2."[20] Rather than use the emissions data and modeling available to Minnesota in 2018, or even emissions data and modeling available at the time of the proposed SIP disapproval, EPA made a number of additional updates to its emissions inventories and model design to construct a new 2016v3 emissions platform, which it used to generate new air quality modeling without seeking public comment to allow affected party input to help the agency assess the accuracy of the new information utilized in the modeling.[21] Minnesota was now no longer linked to two downwind receptors. It was now linked to only a single maintenance-only receptor, at a maximum contribution of 0.85 ppb for 2023.[22]

While EPA also conducted updated modeling for 2026, it did not release this information in the docket for the SIP Disapproval, stating it was "not applicable" and "not used in this final action."[23] EPA subsequently made these results available, however, on EPA's website for its Federal Implementation Plan ("FIP") for 23 states, including Minnesota.[24] Based on EPA's modeling for 2026, Minnesota is not linked to any downwind nonattainment or maintenance-only receptor. In fact, based on EPA's modeling, the sole maintenance-only receptor Minnesota was linked to in 2023 is in attainment by 2026, and Minnesota's largest contribution to any

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[17] Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838, 9868 (February 22, 2022) ("Proposed Rule").
[18] Proposed Rule at 9867.
[19] *Id.* at 9868.
[20] *See* SIP Disapproval at 9357.
[21] *See id.* at 9339.
[22] *Id.* at 9357.
[23] *Id.* at 9344, n.49.
[24] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs

downwind nonattainment or maintenance-only receptor is just 0.32 ppb.[25] Notably, this modeling assumed no installation of additional pollution controls in Minnesota. The only emissions reductions included from Good Neighbor obligations were an annual reduction of 139 tons NOx from emissions control optimization at EGUs.[26]

II. Grounds for Reconsideration of the SIP Disapproval

Reconsideration is justified under either CAA § 307(d)(7)(B)[27] or Administrative Procedure Act ("APA") § 553(e) (5 U.S.C. § 553(e)).[28] Under CAA § 307(d), reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[29] Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020). Under the APA, EPA has "broad discretion to reconsider" its SIP Disapproval "at any time" Under the APA. *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).[30]

Three grounds support reconsideration under either standard. First, EPA's 2016v3 modeling did not have the benefit of Petitioners' or other public comments. As a result, it contains a significant overestimation of 2023 emissions for Minnesota. Second, EPA's 2016v3 modeling of the sole monitor supporting a potential linkage between Minnesota and Illinois is subject to significant bias which, if corrected for, results in the same receptor modeling attainment in 2023. Third, EPA's rejection of prong 2 of Minnesota's SIP was procedurally

[25] *See* Federal "Good Neighbor Plan" for the 2016 Ozone National Ambient Air Quality Standards, https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf, at 198 (pre-publication version).
[26] Compare *Id.* at 290, Table V.C.1-1; 291, Table V.C.1-2; and 452, Table VI.B.4.c-1.
[27] 42 U.S.C. § 76076(d)(7)(B).
[28] SIP disapprovals are not automatically subject to the exhaustion requirements of Clean Air Act § 307(d). 42 U.S.C. § 7607(d). This subsection lists 22 categories of agency action subject to the exhaustion requirement. SIP approval and disapproval, separate from issuance of a FIP, as occurred in the SIP Disapproval, is not addressed by any of these 22 categories.
[29] 42 U.S.C. § 7607(d)(7)(B).
[30] *See also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.")

improper because it was based entirely on results EPA obtained in 2023, well past the statutory deadline for Minnesota's SIP submission and EPA's decision approving or disapproving it.

A. Errors in EPA's New Emissions Data and Modeling, Which Were Not Subject to Notice and Comment, Support Reconsideration to Ensure EPA's Decision on Minnesota's SIP is Based on Valid and Accurate Information.

EPA "made a number of updates to [its] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval uses "this updated modeling to inform [EPA's] final action on [state] SIP submissions," including Minnesota's. *Id.*

The new emissions inventory and modeling platform are of central relevance to EPA's rule. EPA identifies the 2016v3 platform as designed "to inform [the agency's] final action on these SIP submissions." SIP Disapproval at 9339. For Minnesota, the 2016v3 modeling results are the sole record citation EPA provides for its finding that prong 2 of Minnesota's SIP was "ultimately inadequate." *Id.* at 9357.

While there have been errors in each of EPA's inventories at each stage of the regulatory process, these new errors in the emissions inventory arose only with the publication of the final SIP Disapproval. Under both the APA and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment on the evidence on which EPA intends to rely for its final rules.[31] EPA's emissions inventory and modeling design changes were not made publicly available until EPA published the SIP Disapproval and several supporting documents on the same day. As a result, the public, including Petitioners, did not have the opportunity to review EPA's data and correct errors before then.

In the limited time Petitioners have had to review the 2016v3 data, we have identified significant errors in EPA's estimate of NOx emissions for 2023. As an example, EPA added 2,822 tons of NOx for Northshore Mining Co. – Silver Bay power. These boilers have been idled since October 2019 and are expected to have zero emissions in 2023. EPA itself recognizes that zero emissions are expected at this facility in both its OTP Policy Analysis, Appendix A and in its Unit-Level Allocations and Underlying Data for the Final Rule (both available at https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs). Yet EPA made no adjustment to its 2016v3 data, resulting in a significant overestimate of 2023 emissions from Minnesota used by EPA to justify disapproval of the Minnesota SIP. If EPA defends including 2,822 tons of NOx emissions for Silver Bay Power in the baseline actual emissions used to model Minnesota's downwind impact in 2023, then Minnesota's state allowance budget should be

[31] *See Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 540 (D.C. Cir. 1983) (adding evidence on which EPA relies after the close of the comment period would be "highly improper"); *see also Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981) ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations).

increased to reflect those emissions and Silver Bay Power should receive proportional allowance allocations for the 2023 CSAPR ozone season trading program and beyond. To do otherwise would be internally inconsistent, which is an indication of arbitrary rulemaking.

For Minnesota, EPA's most recent modeling identified a single impacted maintenance monitor in 2023, at which Minnesota's maximum impact was 0.85 ppb. EPA's latest modeling projects this same receptor will be in attainment by 2026 with no reductions from Minnesota other than already "on the books" rules and regulations.[32] In other words, EPA's 2026 modeling confirms Minnesota's 2018 SIP conclusion that "the limits and controls that Minnesota already has in place across the state are sufficient to make it reasonably certain that Minnesota will not significantly contribute to nonattainment or interfere with maintenance in any other state" and that "no further controls or emissions limits are required to fulfill [Minnesota's] responsibilities under the interstate transport provisions for the 2015 ozone NAAQS under prongs 1 and 2 of Section 110(a)(2)(D)(i)(I)."[33]

Given the above considerations, EPA should grant reconsideration to reassess Minnesota's 2018 SIP in light of its own modeling showing that no further emission reductions are needed for Minnesota to satisfy its prong 2 good neighbor obligations.

B. The Sole Monitor that Links Minnesota Models in Attainment for 2023 When Bias is Removed.

Minnesota's only link to a downwind state receptor is the Alsip/Village Garage monitor located in Cook County, Illinois (170310001). This monitor is located near the southern shore of Lake Michigan at a land-water interface with complex meteorology**.** This monitor is currently measuring attainment with the 2015 ozone NAAQS using the 2021 4th highest daily maximum value (68 ppb). However, EPA's air quality modeling predicts that this monitor is at risk of violating the ozone NAAQS and, therefore, designates it as a maintenance-only receptor. Upwind states that interfere with this monitor's maintenance of the ozone NAAQS are linked through prong 2**.** However, if a corrected model predicts the monitor's maximum 2023 design value will attain the 2015 ozone NAAQS, this monitor falls out of the analysis at Step 1 and, since no other monitor links to Minnesota, EPA will have no basis for disapproval of prong 2 of Minnesota's SIP.

In the attached analysis, Alpine Geophysics demonstrates that the Cook County monitor models attainment for the 2015 ozone NAAQS in 2023. Alpine Geophysics evaluated this Cook County monitor and concluded that its location at a land-water interface at the southern shore of Lake Michigan presents highly complex meteorological conditions and ozone photochemistry that complicate the air quality model's ability to replicate ozone concentrations reliably. Of note,

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[32] *See* Air Quality Modeling Final Rule Technical Support Document, https://www.epa.gov/system/files/documents/2023-03/AQ%20Modeling%20Final%20Rule%20TSD.pdf at 17, Table 3-5 (showing Monitor 170310001 no longer listed as a monitor-only receptor in the 2026 base case).
[33] 2018 SIP at 13.

EPA's application of a 12 km grid resolution in such areas is contrary to EPA's own guidance.[34] Alpine Geophysics reviewed EPA's day-specific model performance for the estimation of ozone concentrations on days EPA used to calculate future year design values and found significant bias in the majority of modeled day values used to designate this monitor site as a maintenance-only receptor. When Alpine Geophysics adjusted for this bias by using daily concentration values within acceptable normalized bias boundaries (+/- 15%), the updated list of top ten days used to designate the Cook County monitor resulted in both its average and maximum design values to be calculated in attainment with the 2015 ozone NAAQS.

When one attaining monitor modeled as a maintenance-only receptor is the sole basis for a state's linkage, a refined level of analysis is particularly important when predicting future design values and significant contribution**.** When that monitor is in a highly complex land-water interface area, it is not surprising for refined analysis to show significant bias**.** In its FIP rulemaking, EPA looked at this impact, but evaluated only one of ten Cook County monitors.[35] In doing so, EPA evaluated the only monitor out of the ten where EPA's performance-based recalculation resulted in a higher design value. As a result, EPA's sensitivity analysis materially understates the significance of the bias impact on the Alsip/Village Garage monitor and this issue remains central to EPA's evaluation of Minnesota's 2018 SIP.

Petitioners also had no ability to evaluate the bias in EPA's 2016v3 modeling of the Alsip/Village Garage monitor prior to EPA's release of its model and supporting data. As a result, this information arose after the close of the public comment period and within the time for judicial review.

Since Petitioners have identified significant bias in the sole receptor on which EPA relies to find a link to Minnesota and reject Minnesota's 2018 SIP, reconsideration is appropriate to evaluate the new information and analysis provided. When reasonably adjusting for the bias in EPA's 2016v3 modeling of that receptor, EPA will be in a position to confirm that Minnesota accurately concluded in 2018 that there are no "potential nonattainment or maintenance receptors significantly impacted by ozone transport from Minnesota in 2023" and that "[t]herefore, Minnesota does not have a responsibility to identify or implement any further controls or emissions limits to reduce downwind ozone contribution."[36]

C. Minnesota's SIP Should Have Been Approved Based on the Data Available at the Statutory Deadlines for Submission or Review.

The Clean Air Act sets out a detailed process for EPA's review of SIPs in CAA § 110(k). 42 U.S.C. § 7410(k). For timely submitted plans that have been deemed complete, like Minnesota's,

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[34] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze, https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf (Nov. 29, 2018).

[35] *See* Federal "Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Response to Public Comments on Proposed Rule, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf at 196.

[36] 2018 SIP at 9.

EPA has twelve months to act on a plan submission. 42 U.S.C. § 7410(k)(2). For a plan that meets the requirements of the Clean Air Act, "the Administrator shall approve such submittal as a whole." *Id.* at (k)(3). If a portion of the plan revision meets all the applicable requirements, EPA "may approve the plan revision in part and disapprove the plan revision in part" but "[t]he plan revision shall not be treated as meeting the requirements of [the Clean Air Act] until the Administrator approves the entire plan revision as complying with the applicable requirements of [the Clean Air Act]." *Id.* In other words, while EPA has discretion to partially approve a SIP submittal that does not meet all requirements of the Clean Air Act, if a submission meets all requirements of the Act, EPA does not have discretion. It must approve the SIP. *See also Utah Physicians for a Healthy Env't v. Kennecott Utah Copper, LLC*, 191 F. Supp. 3d 1287, 1290 (D. Utah 2016) ("If a SIP satisfies the applicable requirements, EPA must approve it.").

In 2018, Minnesota submitted a timely and approvable SIP. As EPA acknowledges in the SIP Disapproval, Minnesota "was not projected to be linked to any receptor in 2023 in the EPA's 2011-based modeling."[37] Petitioners retained Alpine Geophysics to reanalyze Minnesota's SIP submission considering the best evidence available both at the time of Minnesota's SIP submission and at the time of EPA's statutory obligation to approve or disapprove Minnesota's SIP. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota's SIP submission: (1) had no material errors; (2) relied on the best science (including emissions data and modeling) available at the time; (3) fully complied with the CAA's requirements and EPA's guidance; and (4) would have been approved had EPA not incorporated information unavailable during the statutory review period. As a result, pursuant to 42 U.S.C. § 7410(k)(2) and (k)(3), by April 1, 2020, EPA had a non-discretionary duty to approve Minnesota's SIP. While EPA missed its statutory deadline, this did not relieve EPA of its duty to approve Minnesota's SIP.

While EPA now finds that "in light of more recent air quality analysis," Minnesota is linked to a single maintenance monitor in Illinois, this is based on information that did not exist at the time of Minnesota's SIP submission nor when EPA had a statutory obligation to approve the SIP. This was also not EPA's first use of untimely information to assess Minnesota's SIP. In 2022, EPA proposed to disapprove Minnesota's SIP "[s]ince new modeling ha[d] been performed by EPA with updated emission data," that EPA proposed "to primarily rely on … to identify nonattainment and maintenance receptors in 2023." Proposed Rule at 9867. As EPA acknowledged at the time, this was "a different method for projecting emissions" than what had been available to Minnesota for it to develop its SIP submittal. *Id.* EPA's repeated changes in emissions inventory and modeling platform after the deadline for SIP submissions and after Minnesota's SIP was deemed complete by EPA effectively moved the goalpost for Minnesota's SIP, undercutting the State of Minnesota's ability to identify the requirements EPA would apply to determine an approvable SIP.

The impact was significant. Minnesota's modeled impact went from contributing "below 1 percent of the NAAQS to receptors in 2023" to contributing "greater than 1 percent of the standards to two maintenance-only receptors in Illinois"[38] in the 2022 proposed SIP Disapproval

[37] SIP Disapproval at 9357.
[38] *Id.* at 9867-68.

to now being linked to one maintenance-only receptor in the 2023 SIP Disapproval (assuming no further adjustment for bias or data inaccuracies)). Notably, even using EPA's new data and modeling, Minnesota would still have had no linkage to a downwind maintenance receptor if EPA had not also moved the maximum threshold it indicated it would consider acceptable from 1 ppb to 1% (0.70 ppb).[39] As the D.C. Circuit has held, it is arbitrary and capricious to give states a "constantly moving target," *New York v. EPA*, 964 F.3d 1214, 1224 (D.C. Cir. 2020), let alone two. The language and structure of the Clean Air Act clearly give Minnesota and Petitioners the right to address this new data in the first instance in a SIP amendment, and not in a challenge to a SIP disapproval, as EPA now requires.

Notably, if EPA had followed the CAA procedures, it could have appropriately considered the new information it has developed since 2020, including the 2016v3 modeling it has introduced with the 2023 SIP Disapproval. But EPA cannot rely on its almost three year delay to circumvent the process and procedural protections set forth in the Clean Air Act. Rather, EPA was required to act on the SIP Minnesota submitted. If, after approval, EPA finds that a timely, complete and approved SIP nonetheless is "substantially inadequate … to mitigate adequately the interstate pollutant transport" or otherwise comply with the requirements of the Clean Air Act, "the Administrator shall require the State to revise the plan as necessary to correct such inadequacies." *Id.* at (k)(5). EPA also cannot simply disapprove the state's plan pending a new state submission that incorporated EPA's newly developed information, as the SIP Disapproval effectively does. In the event EPA finds a SIP Call is justified, EPA must first "notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions." *Id.* Further, "[s]uch findings and notice shall be public." *Id.* These procedural protections are an important component of the cooperative federalism embodied in the Clean Air Act. As courts have held, "[t]he Clean Air Act is an experiment in federalism, and the EPA may not run roughshod over the procedural prerogatives that the Act has reserved to the states, especially when … the agency is overriding state policy. *Bethlehem Steel Corp. v. Gorsuch*, 742 F.2d 1028, 1036–37 (7th Cir. 1984).

Multiple commenters, including the Minnesota Pollution Control Agency, have raised similar concerns arising from EPA's initial proposal to use 2016v2 modeling to disapprove state SIPs.[40] EPA has attempted to respond to those comments in the RTC, but in doing so, has not addressed the fundamental issue that EPA cannot disapprove a SIP that is approvable based on the information existing at the time that submittals are due, or even at the time EPA's SIP review was statutorily due, and cannot circumvent Minnesota's right to address new data in a SIP amendment, before EPA uses it to disapprove an otherwise approvable SIP. 42 U.S.C. §§ 7410(k)(3) and (5).

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[39] Minnesota did not rely on the 1 ppb threshold for its SIP submission, but as EPA acknowledged, "[t]he 2018 modeling indicated the state was not projected to contribute above one 1 percent of the NAAQS to a projected downwind nonattainment or maintenance receptor. Therefore, the state may not have considered analyzing the reasonableness and appropriateness of a 1 ppb threshold at Step 2 of the 4-step Step interstate transport framework per the August 2018 memorandum." Proposed Rule at 9867.

[40] *See* RTC at 42-59.

EPA asserts in the SIP Disapproval that its use of new modeling and data did not move the goal post for states because EPA "did not evaluate states' SIP submissions based solely on the 2016v2 emissions platform (or the 2016v3 platform…)" but rather "evaluated the SIP submissions based on the merits of the arguments put forward in each SIP submission." SIP Disapproval at 9366. For Minnesota, however, EPA cites no basis or analysis for its SIP Disapproval other than the 2016v3 modeling results. Having relied on no other information to disapprove Minnesota's SIP, EPA cannot simply assert it had an additional basis with no additional substantiation. As the D.C. Circuit has noted, EPA cannot support its decision on only a "Delphic explanation of [Minnesota's] purported failure to carry its burden of proof." *New York*, 964 F.3d at 1224.

EPA also maintains that data and modeling it developed for the Proposed Rule in 2022, and now additional data and modeling it developed for the SIP Disapproval in 2023, supports a finding that Minnesota's SIP submission is "ultimately inadequate." SIP Disapproval at 9357. But even if this were the case, it does not give EPA a right to disapprove Minnesota's 2018 SIP. For data arising after EPA's statutory deadline to approve Minnesota's SIP, EPA could no longer rely on its obligation to use the "best information available." SIP Disapproval at 9366. Interpreting the Clean Air Act otherwise would not do justice to the cooperative federalism framework Congress established in CAA § 110, and would deprive states of important procedural protections allowing them to control and direct in the first instance, the implementation of the NAAQS within their borders.

The SIP Disapproval misapplies the D.C. Circuit's reasoning in *Wisconsin*, 903 F.3d at 322, when it asserts the SIP submission deadline is "'procedural'" and that to limit EPA's decision to information available at the time of the SIP submission or EPA's statutory review deadline would elevate it above requirements "'central to the regulatory scheme.'" SIP Disapproval at 9366 (quoting *Wisconsin*, 903 F.3d at 322. Neither *Wisconsin*, nor the case on which it relies, *Sierra Club v. EPA*, 294 F.3d 155 (D.C. Cir. 2002), addressed the issue presented here. In *Wisconsin*, the court was responding to an argument that EPA should have selected 2011 as its analytic year even though that year had already passed. In *Sierra Club*, the court was responding to a contention that EPA's ability to extend a SIP submittal deadline should support its authority to extend attainment deadlines. Here, EPA argues for an exception that would swallow the rule. If EPA could simply withhold ruling on a SIP until the State's information had become stale, and then disapprove the SIP and issue a FIP based on the "best available information," the cooperative federalism structure of the NAAQS would be an empty shell.

This is also not a situation like that which arose in *EME Homer City Generation, L.P. v. EPA,* 795 F.3d 118 (D.C. Cir. 2015). There, EPA had approved state SIPs in reliance on the Clean Air Interstate Rule ("CAIR"), which was subsequently found to have "more than several fatal flaws" by the D.C. Circuit. *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C.Cir.2008) (*per curiam*). In addressing whether this ruling allowed EPA to "correct" its earlier SIP approvals under 42 U.S.C. § 7410(k)(6), the D.C. Circuit found EPA could do so, but only due to the unique circumstances of that case. *EME Homer City Generation*, 795 F.3d at 135 n.12 ("Our conclusion on Subsection 7410(k)(6) is limited to the unusual circumstances here, in which a federal court says that EPA lacked statutory authority at the time to approve a SIP."). Notably, the D.C. Circuit

did not decide whether EPA could rely on Clean Air Act §110(k)(6) to disapprove an approved SIP "in any other circumstances," and stated that its holding in particular "should not be read to diminish the scope or force of Subsection 7410(k)(5), which provides that whenever 'the Administrator finds that the applicable implementation plan for any area is substantially inadequate ... the Administrator shall require the State to revise the plan as necessary to correct such inadequacies.'" *Id.* (quoting 42 U.S.C. § 7410(k)(5)).

While in *EME Homer,* EPA had already approved several state SIPs, and in this rulemaking EPA has not yet approved Minnesota's SIP, this is a distinction without a difference. Minnesota submitted its SIP on October 1, 2018. It was deemed complete April 1, 2019.[41] EPA's period for review therefore ended April 1, 2020. As described in the Proposed Rule, Minnesota's SIP submission complied with the Clean Air Act and EPA's guidance for developing an interstate transport SIP for the 2015 ozone NAAQS. 87 Fed. Reg. at 9848-49. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota timely submitted an approvable SIP. By April 1, 2020, EPA had a statutory duty to approve Minnesota's SIP.

EPA's reliance on its 2016v3 modeling platform (which was not available to the public or interested parties) to reject the conclusions Minnesota reached based on the information that was available to all parties at the time is clearly of central relevance. Had EPA acted by its statutory deadline, Minnesota would have an approved SIP today. Further, while Petitioners have previously commented on the approvability of Minnesota's SIP, the basis for EPA's partial SIP Disapproval for Minnesota, including its decision to rely on its newer 2016v3 modeling platform, was not made public until the final rule. These grounds therefore arose after the close of the public comment period but before the time for judicial review. Reconsideration is therefore appropriate to address this procedural anomaly for Minnesota.

On reconsideration EPA should approve Minnesota's 2018 SIP based on the information that was available to EPA for its statutory review. The agency may then reassess whether, based on the information available today, including the above data and bias corrections, Minnesota's SIP remains sufficient to comply with prong 2 of the state's Good Neighbor obligations. For the reasons explained herein, EPA should find that the 2018 SIP was and is adequate to comply with prong 2.

III. Grounds for Stay of the SIP Disapproval

EPA has authority to stay the SIP Disapproval both pending reconsideration and pending judicial review. First, if the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration can be granted for three months. Second, EPA has authority under the APA to stay the SIP Disapproval pending judicial review.

[41] *See* https://www3.epa.gov/airquality/urbanair/sipstatus/reports/mn_infrabypoll.html

A. A Stay Under CAA § 307(d)(7) is Appropriate.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). If the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration is justified here.

EPA issued a final rule based primarily on emissions data and modeling that it did not make publicly available before issuance of the final rule. Even upon publication, EPA's release of data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the data and checking its accuracy has taken several weeks. It would take many more weeks to rerun EPA's modeling to confirm that the results support reversal of EPA's disapproval of prong 2 of Minnesota's SIP. It will likely take a similar amount of time to evaluate the evidence of bias Petitioners are submitting to confirm that it too, supports approval of Minnesota's SIP.

A stay will also not unduly impact downwind states. Minnesota is not modeled to interfere with attainment for any downwind state. Under EPA's most recent modeling, Minnesota is linked only to a single maintenance-only receptor, the most recent monitored design value of the monitor at this location was in attainment, and EPA's modeling for 2026 shows the receptor will model attainment as well with only minimal reductions from Minnesota. As EPA has itself emphasized, the SIP Disapproval does not require any action from the states.[42]

While a stay of the effective date of the SIP Disapproval for Minnesota would also prevent EPA from applying its FIP to Minnesota at the start of the upcoming ozone trading season, which is scheduled to start May 1, 2023, this is not likely to be relevant. In a recent filing, EPA has stated that the FIP is not likely to be effective until "late June to early July."[43] If EPA timely takes action on this reconsideration, this is well within the time EPA would need to conduct reconsideration. Further, while EPA has interpreted the CAA to require it "to address good neighbor obligations as expeditiously as practicable and no later than the next attainment date," RTC at 445, granting a stay of Minnesota's SIP denial pending reconsideration will not interfere with that goal. Minnesota is modeled to impact only a single maintenance-only monitor. As the D.C. Circuit has recognized, this 'may be a valid reason" to postpone addressing emission reductions until even after the next attainment date. *North Carolina v. EPA*, 531 F.3d 896, 912 (D.C. Cir. 2008). A reasonable stay to address reconsideration falls well within EPA's discretion.

B. EPA Should Stay the Effective Date of the SIP Disapproval Pending Judicial Review.

EPA can consider a stay of the entire SIP Disapproval for all affected states. Under the APA, EPA may stay the effective date of the SIP Disapproval pending judicial review when "justice

[42] *See, e.g.*, 2015 Ozone NAAQS Interstate Transport SIP Disapproval – Response to Comments ("RTC") at 466.
[43] Respondents' Consolidated Response in Opposition to the Motions for Stay of the Final Rule, *Texas v. EPA*, Case No. 23-60069, Doc. 109, at 12 (5th Cir. Filed March 27, 2023).

so requires." 5 U.S.C. § 705. Several Petitioners are filing a petition for judicial review of EPA's partial disapproval of Minnesota's SIP contemporaneously with this petition for reconsideration and stay. Multiple other petitions have already been filed for judicial review, including petitions by Arkansas, Kentucky, Oklahoma, Texas, Utah, and Wyoming. More are likely. These cases are already spread across four circuits, and additional litigation may expand the number of courts further.

The effective date of the SIP Disapproval is March 15, 2023. This effective date is significant for both legal and practical reasons. Legally, it will force EPA to promulgate a FIP within two years (though in this case EPA has already finalized its FIP). 42 U.S.C. § 7410(c)(1). States will also be required to prepare SIP revisions if they are interested in addressing the errors in EPA's analysis. Further, the significant legal flaws in EPA's SIP Disapproval discussed above, coupled with the technical and legal concerns it raises, make it likely that judicial review will result in a remand if not vacatur of the current SIP Disapproval. As a result, to avoid the unnecessary expenditure of EPA resources on a FIP, state resources on SIP revisions, and the resources of the public and regulatory industries in addressing a FIP that is likely to not be required, justice requires that the SIP Disapproval be stayed pending judicial review.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors indicate support for EPA in granting a stay of the SIP Disapproval. Under this standard, the considerations for a stay are:

(1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits;

(2) whether the applicant will be irreparably injured absent a stay;

(3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and

(4) where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

1. Petitioners Have Made a Strong Showing They Are Likely to Succeed on the Merits

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id. (quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the SIP Disapproval has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's partial SIP Disapproval for Minnesota was based on an incorrect set of emissions data and biased modeling results that, when adjusted, support Minnesota's original conclusion that the state is not linked to downwind nonattainment or interference with maintenance and, even if linked, does not need to impose additional emission reductions to satisfy its Good Neighbor obligations. Procedurally, EPA did not follow the process required by the Clean Air Act for reviewing and approving Minnesota's SIP. In doing so, EPA deprived the State and Petitioners of the ability to address EPA's concerns in a SIP Call process.

Other flaws in the SIP Disapproval also strongly support a showing of likely success on the merits in a judicial challenge. In particular, we call to the agency's attention: (a) EPA's impermissible reliance on new data to disapprove prong 2 of Minnesota's SIP without providing adequate notice and an opportunity for public comment; and (b) the SIP Disapproval's subversion of the well-established and vital cooperative federalism underlying the entire Clean Air Act and in particular, the NAAQS.

a. *EPA Cannot Base its SIP Disapproval on Information that was Not Subject to Adequate Notice and Public Comment*

Under both the Administrative Procedure Act ("APA") and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id.* at 540. Adding evidence on which EPA relies after the close of the comment period is "highly improper." *Id.* at 540; *see also Sierra Club*, 657 F.2d at 400 ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."). Even reconsideration cannot cure an inadequate opportunity for notice and comment. *U. S. Steel v. EPA*, 595 F.2d 207, 214 (5th Cir. 1979) ("Permitting the submission of views after the effective date is no substitute for the right of interested persons to make their views known to the agency in time to influence the rulemaking process in a meaningful way.") (Internal quotations omitted).

In the SIP Disapproval, EPA "made a number of updates to [it's] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval used "this updated modeling to inform [EPA's] final action on [Minnesota's] SIP submissions." *Id.* The details of these emissions inventory and modeling design changes were first described to the public in the SIP Disapproval and associated documents made publicly available the same day.[44] Even then, EPA did not make public its 2026 modeling results, reserving these for finalization of the FIP several weeks later.

[44] Even then, the supporting data and modeling platform were not made electronically available and needed to be requested by the public, which added several more weeks to gain access.

This data and modeling were clearly of central importance to EPA's disapproval of prong 2 of Minnesota's SIP. In fact, they are the sole basis for EPA's disapproval. *See* SIP disapproval at 9357 (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"); *see also id*. (disapproving prong 2 of Minnesota's SIP because "[i]n the 2016v3 modeling, Minnesota is projected to be linked above 1 percent of the NAAQS to one maintenance-only receptor"). As a result, EPA was required to provide the public advance notice of its new data and an opportunity for meaningful public comment.

EPA's publication of its revised emissions inventory and modeling the day of the SIP Disapproval did not satisfy this requirement. In *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982), the D.C. Circuit found EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations. Here, EPA did not make its new emissions data and modeling publicly available until the *day* it published its final SIP Disapproval.

It is not enough to say that Petitioners had the opportunity to comment on EPA's previous version of the emissions data and modeling, or that EPA's latest data simply "incorporates comments generated during the public comment period." SIP Disapproval at 9366. As the D.C. Circuit stated in *Chesapeake*, 952 F.3d at 320, it would be an "unreasonable burden on commenters not only to identify errors in a proposed rule but also to contemplate why every theoretical course of correction the agency might pursue would be inappropriate or incorrect." The new data and modeling on which EPA relies for the SIP Disapproval differs significantly from that which was in the public record. Based on EPA's own summary of the data, Minnesota's largest contribution to a downwind maintenance receptor changed from 0.97 ppb to 0.85 ppb based on EPA's changes. *Compare* Proposed Rule at 9868 *with* SIP Disapproval at 9354. Since EPA's own adopted significant contribution threshold in the SIP Disapproval is 0.7 ppb, a change of 0.12 ppb is clearly significant.[45]

Under both the CAA and the APA, EPA was required to provide notice and an opportunity for public comment on its 2016v3 data. There is no question that EPA provided no notice or opportunity for comment. As a result, there is a high likelihood that Petitioners would be likely to prevail on the merits of a judicial challenge. This strongly supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

b. *EPA Undermined State Primacy by Disapproving Minnesota's SIP Despite its Adherence to the Requirements of the Clean Air Act.*

As EPA acknowledges, "[t]he CAA establishes a framework for state-Federal partnership to implement the NAAQS based on 'cooperative federalism.'" SIP Disapproval at 9367. Under this model, "the Federal Government establishes broad standards or goals, states are given the

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[45] EPA's 2016v3 modeling did not just result in significant changes to EPA's assessment of Minnesota's potential impact on downwind states. Six states (Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming) had their status as linked states change entirely. *See* Air Quality Modeling Technical Support Document 2015 Ozone NAAQS SIP Disapproval Final Action, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0663-0017 at 24.

opportunity to determine how they wish to achieve those goals, and if states choose not to or fail to adequately implement programs to achieve those goals, a Federal agency is empowered to directly regulate to achieve the necessary ends." *Id.* Thus, "states have the obligation and opportunity in the first instance to develop an implementation plan to achieve the NAAQS under CAA section 110" and "EPA will approve SIP submissions under CAA section 110 that fully satisfy the requirements of the CAA." *Id.* As the Supreme Court has held: "[e]ach State is given wide discretion in formulating its plan, and the Act provides that the Administrator 'shall approve' the proposed plan if it has been adopted after public notice and hearing and if it meets [the CAA's] criteria." *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976) (*quoting* 42 U.S.C. § 7410(a)(2)).

EPA departed from this framework when it proposed a SIP disapproval based, not on any inaccuracy in Minnesota's evaluation of the data, but on EPA's preference for a different modeling platform and emissions inventory. EPA does not have the authority to condition SIP approval on the state's adoption of EPA's preferred approach, or to supplant Minnesota' interpretation of how best to achieve the goals of the CAA, as long as Minnesota complies with the requirements of the CAA.

EPA's position is predicated on an incorrect summary of its role in the SIP review process and the relevant case law. First, EPA's role is not "secondary" only in that "it occurs second in time." RTC at 425 (internal quotations omitted). EPA relies on *EPA v. EME Homer City Generation*, LP, 572 U.S. 489 (2014) for this proposition, but the case does not support EPA's position. It must be remembered that *EME Homer* involved EPA's authority to promulgate a FIP after EPA had already disapproved SIPs.[46] As a result, the Court did not address EPA's statutory duty to approve a timely and complete SIP submission, which is the issue here. The Court's "interpretations of CAA section 110(a)(2)(D)(i)(I)" on which EPA relies must be read in this light. RTC at 426. The Court upheld interpretive choices EPA made when issuing a FIP. The Court did not say EPA could delay approval until new information became available that supported its disapproval of the SIP.

Second, EPA is wrong to imply that *EME Homer* undermines the long line of cases setting out EPA's secondary (in substance, not just in time) role in developing plans to implement the NAAQS. In fact, the Supreme Court continues to cite these cases for their interpretation of EPA's role. *See West Virginia v. EPA*, 213 L. Ed. 2d 896, 142 S. Ct. 2587, 2600 (2022) ("EPA … does not choose which sources must reduce their pollution and by how much to meet the ambient pollution target. Instead, Section 110 of the Act leaves that task in the first instance to the States, requiring each 'to submit to [EPA] a plan designed to implement and maintain such standards

[46] *See EME Homer*, 572 U.S. at 507 ("The gravamen of the State respondents' challenge ***is not that EPA's disapproval of any particular SIP was erroneous***. Rather, respondents urge that, notwithstanding these disapprovals, the Agency was obliged to grant an upwind State a second opportunity to promulgate adequate SIPs once EPA set the State's emission budget. ***This claim does not depend on the validity of the prior SIP disapprovals***. Even assuming the legitimacy of those disapprovals, the question remains whether EPA was required to do more than disapprove a SIP, as the State respondents urge, to trigger the Agency's statutory authority to issue a FIP.") (emphasis added).

within its boundaries.'") (*quoting Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 65 (1975)).

The SIP Disapproval and RTC makes clear that EPA's disapproval of prong 2 of Minnesota's SIP was not based on a determination that Minnesota's SIP failed to meet the statutory requirements of CAA, but because EPA wanted to apply "a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submissions for the 2015 ozone NAAQS under CAA section 110(a)(2)(D)(i)(I)." SIP Disapproval at 9339; *see also id.* at 9340 ("Effective policy solutions to the problem of interstate ozone transport going back to the NOx SIP Call have necessitated the application of a uniform framework of policy judgments to ensure an 'efficient and equitable' approach.") (quoting *EME Homer*, 572 U.S. at 519); RTC at 425-426. This was error. EPA's assessment of a SIP is to be based on whether the SIP compiles with the requirements of the CAA, not on EPA's policy preferences or desire for efficiency. Only after a state fails to comply with its statutory requirements can EPA impose what it believes best to achieve the substantive objective of the Act.

Because EPA's SIP Disapproval is based on improper factors that undermine the core cooperative federalism embodied in CAA § 110, Petitioners are likely to prevail on the merits of a judicial challenge. This further supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

2. Petitioners Will Suffer Irreparable Harm from a Denial of Stay.

Relevant factors for evaluating the harm which will occur include: (1) the substantiality of the injury alleged; (2) the likelihood of its occurrence; and (3) the adequacy of the proof provided. In evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C.Cir.1985)).

The SIP Disapproval poses substantial and imminent injuries to Petitioners. As discussed in Section II above, the data which EPA should have used to evaluate Minnesota's SIP (see Section II.C), the best available data today, when flaws are addressed (see Sections II.A and B), and even the most likely future data (see Section II.D) strongly support a finding that Minnesota is not significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in any state. EPA's SIP denial is predicated on the erroneous conclusion that there *is* interference with maintenance. This places the entire State of Minnesota in an erroneous state of non-compliance with the Good Neighbor requirement of the Clean Air Act.

EPA's SIP Disapproval also forces EPA to promulgate emission reductions through a FIP. 42 U.S.C. § 7410(c). EPA has already finalized just such a rulemaking. This leaves no time for reconsideration or judicial review to run its course before Petitioners are injured by the FIP, let alone time for Minnesota to remedy EPA's issues with the submitted SIP. Petitioners submitted detailed comments on the FIP identifying numerous substantial injuries from EPA's promulgation

of its Proposed FIP that are likely to occur, and supported by substantial evidence, including detailed technical reports.[47] While EPA made substantial modification to the FIP in response to comments, which Petitioners appreciate reflects considerable work on the Agency's part following the public comment period and has addressed many significant issues with the proposed FIP, the final FIP nonetheless includes significant obligations for Petitioners' electric generating units ("EGUs"), starting in the current 2023 ozone trading season (which begins this year). Even Petitioners without EGUs are substantial consumers of electricity, meaning that they will likely bear much of the burden of the higher costs needlessly imposed on Minnesota power producers because of the FIP. Further, while the Proposed FIP is a separate rulemaking, EPA has itself identified the SIP Disapproval as both a necessary step in issuance of a final FIP[48] and the stay of a SIP disapproval that is the basis for a FIP is an appropriate remedy for injuries arising from the FIP itself. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7, 44 n.6 (D.C. Cir. 2012) (Rogers, J., dissenting), *rev'd on other grounds,* 572 U.S. 489 (2014) ("If [states] wish to avoid enforcement of the Transport Rule FIPs because they contend EPA's SIP disapprovals were in error, the proper course is to seek a stay of EPA's disapprovals in their pending cases; if granted, a stay would eliminate the basis upon which EPA may impose FIPs on those States.") (citing 42 U.S.C. § 7410(c)(1)(B)).

3. Staying the SIP Disapproval will not Significantly Injure Other Parties.

As discussed in Section III.A above, the SIP Disapproval does not on its own impose any emission reductions on sources. As a result, a stay will not directly harm any other party. While a stay would also potentially delay the effective date of the FIP, this is unlikely to result in significant injury to other parties. EPA has recently extended a judicially-enforceable deadline to review Good Neighbor SIPs for three states to December 15, 2023 without any mention of public harm from the delay.[49] Even as a stepping stone to a FIP, while a stay will alleviate imminent and irreparable costs, it will not significantly impact NOx emissions. As discussed above, the FIP is unlikely to be effective until after the start of the current ozone trading season, resulting in an attenuated impact on 2023 emissions. Further, even if projected emission reductions for the full 2023 ozone trading season could be achieved, EPA projects total emission reductions from Minnesota of only 139 tons in 2023. This is unlikely to result in any significant impact on the Cook County maintenance monitor.

4. The Public Interest Lies in Granting a Stay.

As courts have held, there is a public interest enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay.

[47] See Comments of U. S. Steel, EPA-HQ-OAR-2021-0668-0798 (June 27, 2022); Comments of Xcel Energy, EPA-HQ-OAR-2021-0668-0411 (June 23, 2022); Comments of Minnesota Power, EPA-HQ-OAR-2021-0668-0539 (June 23, 2022); Comments of SMMPA, EPA-HQ-OAR-2021-0668-0351 (June 22, 2022); Comments of Cleveland-Cliffs Inc., EPA-HQ-OAR-2021-0668-0405 (June 23, 2022)

[48] 88 Fed. Reg. 9336 at 9362.

[49] *See* Joint Notice of Second Stipulated Extension of Consent Decree Deadlines, Doc. 33, *Downwinders at Risk v. Regan*, Case No. 4:21-cv-3551-DMR (N.D. Cal. Jan. 30, 2023).

As discussed in Section II.A above, EPA's SIP Disapproval was promulgated through the inequitable exclusion of public participation into the data central to EPA's final rulemaking. The result will be costly public expenditures, both by EPA to promulgate an unnecessary FIP and States to either prepare to implement EPA's FIP or prepare revised SIPs, and well as unnecessary costs borne by Petitioners.

While it was an error for EPA to disapprove Minnesota's SIP based on information not in the record at the time of submission, EPA can ameliorate the harm of this error by staying the effect of its SIP disapproval until the merits of the issues above can be fully evaluated and addressed.

IV. Conclusion

The State of Minnesota has expended substantial effort and resources to regulate the emission of NOx within its borders. Those efforts have successfully reduced State impacts on downwind receptors to a point that Minnesota is not a significant contributor to nonattainment or interference with maintenance of the 2015 ozone standard in any state. Based on the best available data and modeling science available at the time, Minnesota assessed its impact on downwind states, as it was required to do under the Clean Air Act, and appropriately concluded that it was not interfering with maintenance of attainment in any state. EPA has identified no error or omission in Minnesota's analysis. Nonetheless, based on data that was not available at the time, and in fact was not available to the public until February 2023, EPA partially disapproved Minnesota's Good Neighbor plan for the sole reason that, based on EPA's own modeling, it found a single maintenance receptor in Cook County, Illinois that Minnesota state emissions were impacting at a maximum level of 0.85 ppb. Neither Minnesota, nor Petitioners, were given an opportunity to comment on EPA's modeling, fully evaluate it, or even see it, until EPA published its final SIP Disapproval. While a complete analysis of EPA's modeling would require months, based on Petitioners' review of the data specific to them, and based on expert evaluations by Alpine Geophysics of the modeling and data EPA has provided, EPA's results likely overstate the impact Minnesota is having on the Cook County monitor. Because Petitioners have provided new information that reveals flaws in EPA's emissions inventory for Minnesota and bias in EPA's modeling of the lone monitor that links Minnesota emissions to a downwind state, Petitioners have raised material new data undermining the central basis for EPA's disapproval of prong 2 of Minnesota's SIP. Petitioners therefore request that EPA grant reconsideration of its partial SIP disapproval for Minnesota and approve Minnesota's 2018 SIP. Further, to avoid the significant and irreparable harm to Petitions arising from EPA's erroneous disapproval of prong 2 of Minnesota's SIP, EPA should stay the effectiveness of its SIP Disapproval as applied to prong 2 of Minnesota's SIP pending reconsideration and pending judicial review.

Dated: April 14, 2023

Respectfully submitted,
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Attachment A

TECHNICAL REVIEW OF THE ENVIRONMENTAL PROTECTION AGENCY'S DENIAL OF MINNESOTA'S 2015 OZONE TRANSPORT SIP

Prepared by:
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April 2023

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DOCUMENT OBJECTIVE

The objective of this document is for Alpine Geophysics, LLC to provide technical review and professional opinion of Minnesota Pollution Control Agency's (MPCA) SIP revision to address Clean Air Act (CAA) Section 110(a)(2)(D)(i)(I) and the Environmental Protection Agency's (EPA) final action to disapprove the Minnesota State Implementation Plan (SIP) published on February 13, 2023 in the Federal Register.

This document is formatted into three sections that discuss our review and assessment of the following issues:

A. Whether, given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states;
B. Whether U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary; and
C. Whether the Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

At the end of this document, we also provide a summary of conclusions (Section D) and a regulatory and legislative timeline of actions taken on Minnesota's 2015 ozone SIP for reference (Section E).

A. Given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states.

EPA provided little time for MPCA to review the significant amount of technical information and associated calculations that were used to justify their disapproval of the Minnesota SIP, especially since EPA used a distinct and largely unrelated modeling platform, emissions inventory, and air quality model to justify its action instead of assessing the platform submitted by MPCA in support of its SIP. Notwithstanding the fact that four years and four months passed since the original Minnesota SIP was submitted to EPA, had appropriate time been given to MPCA to review and address EPA's final disapproval, MPCA could have addressed significant flaws in EPA's modeling that EPA itself should have addressed prior to finalizing any SIP disapproval.

It is our opinion that the U.S. EPA should have approved the MPCA's SIP when it was submitted in 2018. However, since EPA has put forward new modeling, we have reviewed this modeling and found several issues with the emissions that EPA used in the new modeling that weigh against using it as a basis for disapproving the Minnesota SIP.

1. EPA inappropriately revised the emission inventory and conducted new air quality modeling for SIP disapprovals without allowing a meaningful opportunity for stakeholder review and comment.

EPA's revisions to the emission inventory used in the modeling it previously has conducted for historic transport rules raises an administrative concern about public review and comment.

EPA notes in the proposed SIP disapprovals that, after the modeling it conducted in support of earlier transport rules, e.g., CAIR, CSAPR, CSAPR Update, CSAPR Closeout, and Revised CSAPR Update, the agency revised the emission inventory used in the modeling to assess the efficacy of prior transport rules. EPA conducted new modeling using this revised inventory and 2016v2 modeling platform. The agency describes the process as follows:

> *Following the Revised CSAPR Update final rule, the EPA made further updates to the 2016 emissions platform to include mobile emissions from the EPA's Motor Vehicle Emission Simulator MOVES3 model and updated emissions projections for electric generating units (EGUs) that reflect the emissions reductions from the Revised CSAPR Update, recent information on plant closures, and other sector trends. The construct of*

> *the updated emissions platform, 2016v2, is described in the emissions modeling technical support document (TSD) for this proposed rule.*[1]

In December 2021, and in response to EPA requests for inventory review and updates[2,3,4], MPCA and other stakeholders submitted detailed comments on the 2016v2 emission inventory platform to correct errors that existed in that platform. EPA's declared efforts to revise this emission inventory platform at this time raised the question about whether EPA intended to update the modeling that has been used as the basis for the SIP disapprovals and the proposed FIP – but only in support of the final rule. EPA's own summary[5] of the comment process includes the statement that "by spring of 2021 it was necessary to make updates to the inventories to perform credible / defensible modeling in CY2021". In this summary, numerous and significant emission, control, and projection factor changes were requested and only with release of the final SIP denials were the changes shared by EPA for review.

As part of these comments, MPCA submitted comments on the 2016v2 emissions modeling platform (EMP) relative to three areas of improvement within Minnesota:

1. Non-electricity generation stationary (non-EGU) point source emissions controls
2. Future year emissions projections for various point and non-point inventory sectors
3. Stationary point EGU growth rate differences between the ERTAC vs IPM models

Non-EGU point source emissions controls

LADCO worked with member states to identify the highest-emitting sources and applicable control technology information for non-EGU stationary point sources in the region. They generated a spreadsheet with the highest-emitting non-EGU sources in 2016 for each LADCO state, including Minnesota, which also included state updates on emissions control information for listed sources.

A provided spreadsheet identified control information and future emission rate changes for several Minnesota sources within the 2016v2 EMP. The control information identified accounts for the installation of low NOx burners at the taconite facilities in Minnesota as part of the Regional Haze Taconite FIP. Based on MPCA estimates, just under 11,000 tpy in NOx reductions were expected due to the controls required by the Taconite FIP. MPCA noted the importance of

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[1] See: IN, IL, MN, OH, and WI proposal at 87 Fed. Reg. 9838 at 9840
[2] http://views.cira.colostate.edu/wiki/wiki/11208#September-21-2021
[3] https://cleanairact.org/wp-content/uploads/2021/10/Wayland_Monitoring-Modeling-and-Emission-Inventory-Updates_9-30-21-1.pdf
[4] https://www.epa.gov/air-emissions-modeling/2016v2-platform
[5] https://gaftp.epa.gov/Air/emismod/2016/v2/reports/comments/Summary_of_2016v2_comments_by_sector_01312022.pdf

having these significant reductions included in the EPA EMP for non-EGUs and requested that EPA do so.

Below is a summary of approximate NOx emission changes for these sources.

- 2,100 tpy at Minorca Mine
- 2,300 tpy at Hibbing Taconite
- 700 tpy at United Taconite
- 3,600 tpy at US Steel Keetac
- 2,100 tpy at US Steel Minntac

Future year emissions projections for various point and non-point inventory sectors

LADCO used US EPA-generated emissions projection reports and identified a list of SCCs that they believed had incorrect future year projection rates. The 2016v2 EMP projection rates were not found consistent either with real-world emissions trends or regional emissions projection information. It was requested that EPA replace the 2016v2 EMP projections for these sources with the updated rates provided by LADCO.

A spreadsheet was provided that included the list of the SCCs with alternative projection information and LADCO comments on the sources of the alternative information.

Stationary point EGU growth rate differences between the ERTAC vs IPM models

LADCO recognized that EPA used the Integrated Planning Model (IPM) to estimate future year EGU emissions, and that the IPM projection methodology differed from the Eastern Research Technical Advisory Committee (ERTAC) EGU model that is endorsed by the MJOs and most of the states in the eastern half of the country. Minnesota noted support for the use of ERTAC EGU projections in the 2016v2 EMP and asked EPA to consider replacing IPM projections with ERTAC EGU projections for sources in the LADCO region in subsequent modeling platforms.

While most states urged EPA to rely on modeling that accurately reflects current on-the-books regulatory requirements and up-to-date emission inventories, they also strenuously object to the possibility that EPA would conduct any such additional modeling to support a final rule. Furthermore, these states object to EPA not providing the opportunity for those data to be reviewed, analyzed, commented upon, and having those comments addressed by EPA in advance of any final decision on the subject SIP disapproval (or for that matter the related FIP). These concerns were also expressed in July 2021 by several MJOs (WESTAR, LADCO, SESARM, MARAMA, and CENSARA).[6]

[6] https://www.regulations.gov/comment/EPA-HQ-OGC-2021-0692-0012

EPA's Previously Unreleased 2016v3 Modeling Platform

EPA's newest emissions inventory and modeling platform are of central relevance to EPA's final rule. The SIP Disapproval itself identifies EPA's "updates to the 2016v2 inventories and model design to construct a 2016v3 emissions platform which was used to update the air quality modeling" and used "this updated modeling to inform its final action on these SIP submissions.[7]" These data and modeling in fact form the basis for EPA's final disapproval of Minnesota's SIP[8] (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"). This issue also arose only with the publication of the final SIP Disapproval. EPA's publication of its revised emissions inventory and modeling did not occur until then, and states had no access to the data, the modeling, or even the results of EPA's modeling until that time.

In the limited time that states have had with the modeling data, significant errors have been identified. A robust public comment process for these data is necessary to correct all significant errors to ensure that EPA's regulatory decisions are based on valid and accurate information. Within Minnesota alone, some of these errors include the following:

- EPA incorrectly included NOx emissions of 2,822 tons in 2023 for Northshore Mining Co. – Silver Bay in the future year air quality modeling and associated significant contribution calculations but not in the engineering analysis used to calculate state level EGU budgets. The subject boilers have been idled since October 2019 and are expected to have zero emissions in 2023;

- EPA predicts zero emissions at Minnesota Power's Laskin Energy Center units that have been converted to natural gas and expect continued MISO dispatch to support the renewables transition and regional grid needs / constraints;

These errors, and many like these presumed in other states in the modeling platform, may significantly impact the results of EPA's analysis and could be the difference in nonattainment and maintenance determinations or whether Minnesota is having a downwind effect on the lone Illinois maintenance monitor that subjects Minnesota to the Good Neighbor provisions of the Clean Air Act.

It is our opinion that the absence of inclusion of Minnesota's and other stakeholder's valid EMP revision submissions, as requested by EPA, and without a rerun of the air quality model in both the base and projection year simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change

[7] 88 FR 9339
[8] 88 FR 9357

nonattainment designations and linked significance using an updated platform, and needs to be considered before making any final decision on denial of MPCA's SIP.

2. The Cook County, Illinois monitor to which Minnesota is linked, is located at the interface of land and water along Lake Michigan and is not properly characterized by EPA's supporting modeling.

EPA did not make a bias adjustment for the only receptor that EPA found "links" Minnesota to downwind interference with maintenance. Observed values at this location (the Alsip/Village Garage monitor) demonstrate significant model overprediction, justifying the need for adjustments to address bias. While EPA has recently investigated bias in southern Lake Michigan, this assessment selectively analyzed only one monitor, which was not representative of the bias observed at the Village Garage monitor. The failue to adequately address bias in EPA's modeling resulted in an overprediction of ozone. Adjusting for this bias supports the conclusion that the Alsip monitor models in attainment of the 2015 ozone NAAQS and therefore Minnesota is not interfering with maintenance at this monitor. EPA's ozone attainment modeling guidance states that:

> *"[t]he most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for both ozone and PM2.5 and regional haze. If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s)"*

EPA's modeling in support of the SIP disapprovals simulated a national domain using a 12km grid resolution domain wide. While this makes running a national, regional simulation easier from a technical perspective, it neglects the important issue of the complex meteorology and/or land-water interfaces in or near the nonattainment or maintenance monitors of interest. Indeed, EPA's choice of a 12km grid is an arbitrary choice in contravention of its own guidance when modeling Illinois monitors in Cook County because these monitors are at land-water interfaces.

Photochemical modeling along coastlines is complex for two reasons. First, the temperature gradients along land/water interfaces can lead to localized on-shore/off-shore flows; and

secondly, the photochemical model formulation spreads the emissions in a grid cell throughout the full grid volume of the cell.

Figure 1 presents a unique area along Lake Michigan that is challenged by these complex meteorologic issues at land-water interfaces. For the Cook County, Illinois monitor with which Minnesota is linked in this final rule, EPA's published model performance evaluation (MPE) metrics for ozone have been reviewed by Alpine on a day-specific basis.

Figure 1. Lake Michigan shoreline monitors located on land/water interface in Illinois.

Studies indicate that air quality forecast models typically predict large summertime ozone abundances over water relative to land and that meteorology around Lake Michigan is distinctly unique; both shortcomings warrant individualized attention and a finer grid resolution to best explore actual conditions.[9,10,11]

The 3x3 neighborhood of grid cells used in determining the design values of the relative response factor (RRF) at land-water interface monitors extends into the noted water bodies. Under current guidance, the top ten modeled days within this 3x3 matrix are used in determining this RRF for each monitor with any cell identified as 50 percent or more water, except for cells including monitors, which are omitted from the calculations.

Table 1 below provides a list of top 10 days at monitor 170310001 (Alsip/Village Garage), the Cook County monitor in Illinois to which Minnesota is linked, and comparisons of daily modeled

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[9] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[10] Abdi-Oskouei, M. , and Coauthors , 2020: Sensitivity of meteorological skill to selection of WRF-Chem physical parameterizations and impact on ozone prediction during the Lake Michigan Ozone Study (LMOS). J. Geophys. Res. Atmos., 125, e2019JD031971, https://doi.org/10.1029/2019JD031971.
[11] McNider, R. T. , and Coauthors, 2018: Examination of the physical atmosphere in the Great Lakes Region and its potential impact on air quality—Overwater stability and satellite assimilation. J. Appl. Meteor. Climatol., 57, 2789–2816, https://doi.org/10.1175/JAMC-D-17-0355.1.

maximum daily average 8-hour ozone concentrations (highlighted in green) and observations on the same date in 2016 (highlighted in blue). These are the dates selected in EPA's modeling to represent the highest modeled days used in estimating future year design values.

As can be seen in Table 1 below, several days selected for RRF calculation have modeled ozone concentrations that fall outside of normally acceptable normalized bias (NBias) boundaries (±15%), here as the result of over (positive bias) predictions compared to observed concentrations on those days. In fact, at the monitor example below, seven of the ten selected days fall outside of the ±15% bias metric (highlighted in orange in the Table) with a maximum normalized bias of 93.60% (observation was 45.25 ppb and modeled concentration was 87.60 ppb; a difference of over 42 ppb).

When these dates are used, EPA's calculation of future year DV is 68.2 ppb (average) and 71.9 ppb (maximum) using the average RRF of 0.9349, identifying this as a maintenance monitor.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160719	73.25	91.07	83.28	0.9144	24.33
2	20160723	45.25	87.60	81.46	0.9298	93.60
3	20160726	64.33	84.02	80.98	0.9637	30.61
4	20160810	85.88	81.35	77.20	0.9490	-5.27
5	20160803	74.38	81.04	75.31	0.9293	8.96
6	20160725	61.88	80.86	76.84	0.9503	30.67
7	20160722	54.50	79.83	76.28	0.9556	46.48
8	20160718	60.75	79.69	76.94	0.9655	31.18
9	20160804	63.75	76.21	66.23	0.8691	19.54
10	20160603	73.63	75.74	69.82	0.9219	2.87
Avg					**0.935**	

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.935	0.935
Future 2023 DV (ppb)	68.2	71.9

Table 1. List of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

If instead a list of the top 10 days with Nbias values within normal acceptable normalized boundaries (±15%) are used, an alternate RRF value is generated, and future year average and

maximum design values used in the nonattainment / maintenance designation process are recalculated.

Table 2 presents a list of top 10 days where the Nbias value is less than the acceptable ±15% normalized bias boundaries. As is seen in this table, all Nbias values fall within the parameters of the acceptable range and dates from the original top 10 list that were already within the boundaries have been maintained and are now the top 3 modeled days in the new list.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) Top 10 RRF - Base Dates (Modeled) –Bias Adjusted - No Water - 3x3					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160810	85.88	81.35	77.20	0.9490	-5.27
2	20160803	74.38	81.04	75.31	0.9293	8.96
3	20160603	73.63	75.74	69.82	0.9219	2.87
4	20160618	67.38	74.79	68.50	0.9158	11.00
5	20160619	76.25	72.60	62.88	0.8662	-4.79
6	20160727	68.75	73.92	68.92	0.9324	7.51
7	20160625	68.13	72.99	66.03	0.9046	7.14
8	20160624	74.88	70.49	66.47	0.9430	-5.86
9	20160802	62.50	71.65	66.87	0.9333	14.64
10	20160524	73.50	69.50	64.27	0.9248	-5.44

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.922	0.922
Future 2023 DV (ppb)	67.3	70.9

Table 2. Alternate bias adjusted list of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

As a result of this bias adjusted calculation, the Alsip / Village Garage monitor located in Cook County, Illinois (170310001) has an average RRF of 0.922, resulting in an average 2023 DV of 67.3 ppb and a maximum DV of 70.9 ppb, identifying this monitor as attainment of the 2015 ozone NAAQS.

Under Step 1 of the ozone transport framework established by EPA, this monitor would not be considered as part of the list of receptors in the significant contribution calculation and therefore any linkages from upwind state contributions would be irrelevant.

Since this is the only monitor in which Minnesota is linked as a significant contributor under EPA's modeling, this linkage would be broken, and Minnesota should be removed from the list of contributing states to downwind receptors.

In the Response to Comments document from the rule, EPA attempted to address the bias issue by preparing an analysis at select monitors in the modeling domain. Specifically, EPA notes[12] that,

> *"Even though the EPA disagrees with commenter's assertion to "throw out" specific days at individual monitors for which model performance does not meet the criteria, out of an abundance of caution, the EPA performed a sensitivity analysis for selected receptors in which the projected 2023 DVs and contributions were recalculated after removing individual days that fell outside the Emery et al., criteria for normalized mean bias and/or normalized mean error. The EPA chose receptors in Coastal Connecticut, the Lake Michigan area, Dallas, and Denver for this analysis. The specific receptors included in this sensitivity analysis are Stratford, Connecticut, Chicago/Evanston, Illinois, Dallas/Denton, Texas, and Denver/Rocky Flats, Colorado."* (emphasis added)

While we agree with EPA's technical approach and calculations in their Chicago/Evanston example provided, EPA's selection of the Evanston monitor is questionable as it is the only monitor out of ten in Cook County, Illinois (three which are identified as maintenance) where performance-based recalculation results in higher design values. This is also not the unique, individual monitor to which Minnesota is exclusively linked. Table 3 presents the ten Cook County, Illinois monitors in EPA's modeling results[13].

As presented in Table 2, using bias-adjusted design values for the individual receptor with which Minnesota is linked (170310001), this monitor is calculated to be in attainment of the 2015 ozone NAAQS in 2023. This decrease is also seen in the remaining Cook County monitors that EPA did not consider in its response to comments on the issue.

[12] See pg. 196, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf

[13] https://www.epa.gov/system/files/documents/2023-03/Final%20GNP%20O3%20DVs_Contributions.xlsx

Site ID	2023 Avg DV	2023 Max DV	Upwind State Contribution (ppb) IN	IA	MI	MN	MO	OH	TX	WI
170310001	68.2	71.9	7.11	0.90	1.16	0.85	0.37	0.68	1.09	2.34
170310032	67.3	69.8	8.22	0.79	1.15	0.60	0.62	1.39	1.40	2.21
170310076	67.6	70.4	6.46	0.80	1.07	0.73	0.49	0.62	1.33	2.49
170311003	64.1	64.7	5.70	0.72	1.03	0.37	0.84	1.22	1.67	2.13
170311601	63.8	64.5	5.85	0.61	2.03	0.59	0.44	1.49	0.78	1.63
170313103	58.4	59.6	4.95	0.38	1.44	0.44	0.46	1.08	0.49	2.32
170314002	64.2	67.3	6.71	0.59	1.48	0.62	0.34	1.09	0.95	3.00
170314007	66.8	68.7	5.33	0.41	1.53	0.49	0.53	1.19	1.03	2.81
170314201	68.0	71.5	5.42	0.42	1.56	0.50	0.54	1.21	1.05	2.86
170317002	68.5	71.3	6.55	0.69	1.00	0.38	1.39	1.04	1.95	2.24

Table 3. Future year design values (ppb) and significant contribution calculations of upwind states to monitors in Cook County, Illinois.

Table 4 demonstrates that the Evanston monitor (170317002) in which EPA used to illustrate a noted increase in design value calculations using a bias adjustment calculation was the only monitor out of the ten where the average and maximum design values increased. Had EPA selected any other monitor from Cook County to demonstrate the bias adjustment, their conclusion may have been different than presented in the Response to Comment document.

			EPA Final Rule		Recalculated w/ Bias Adj		
Site ID	State	County	2023 Avg DV	2023 Max DV	2023 Avg DV	2023 Max DV	Bias Adj DV Change
170310001	Illinois	Cook	68.2	71.9	67.3	70.9	Decrease
170310032	Illinois	Cook	67.3	69.8	66.8	69.3	Decrease
170310076	Illinois	Cook	67.6	70.4	65.9	68.7	Decrease
170311003	Illinois	Cook	64.1	64.7	63.3	64.0	Decrease
170311601	Illinois	Cook	63.8	64.5	63.3	63.9	Decrease
170313103	Illinois	Cook	58.4	59.6	58.4	59.6	No Change
170314002	Illinois	Cook	64.2	67.3	63.2	66.3	Decrease
170314007	Illinois	Cook	66.8	68.7	66.7	68.5	Decrease
170314201	Illinois	Cook	68.0	71.5	67.3	70.7	Decrease
170317002	Illinois	Cook	68.5	71.3	69.0	71.8	Increase

Table 4. EPA final rule and bias-adjusted future year design values (ppb) of monitors in Cook County, Illinois.

Additionally, the LMOS 2017 study[14] shows that for Lake Michigan coastal monitors the air quality model even at a 4 km resolution does not simulate the proper timing and structure of the land/lake breeze or the inland penetration of elevated ozone concentrations. A review of this LMOS study[15] states "To reproduce the timing and magnitude of the ozone time series at coastal monitors, ozone production over the lake must be correctly simulated; furthermore, details of the lake breeze must be accurate——timing, horizontal extent, and vertical structure." Based on recommendations from the LMOS 2017 study research team, a horizontal resolution of at most 1.3 km is required to reasonably resolve the complex meteorology of the air/water interface for the great lakes and coastal ocean areas. The LMOS 2017 Study researchers believe that a 1.3 km grid spacing will assist in the resolution of the large ozone concentration gradients that often occur along the shoreline as well as the inland penetration of the lake breeze circulation.

As the Alsip / Village Garage example shows, days where modeled ozone was predicted at concentrations differing up to ± 42 ppb are being used to estimate future year ozone concentrations and to make determinations of nonattainment, maintenance, and significant contribution from upwind sources.

Furthermore, to adequately capture the inland penetration of the lake breeze, the LMOS report also cites the need for accurate Lake Michigan water temperatures and correct model physics options. EPA's use of the Pleim-Xiu Land Service Model (LSM) does not adequately capture the lake breeze inland penetration. A review of wind vector observations (from the Meteorological Assimilation Data Ingest System (MADIS) network) compared to modeled wind vectors on RRF and significantly contributing days at nonattainment monitors highlights the differences in wind direction and speed during many hours of these predicted high ozone episodes.

On many days with relatively simple meteorology, EPA-developed wind fields using the Weather Research and Forecasting (WRF) Model agree with the MADIS observed winds. However, the modeled winds have strong disagreement with the observed meteorology on June 15, July 7, July 27 and August 4, 2016, the four days when the CAMx model predicted the highest ozone concentrations and are thus used in estimating RRFs and future year ozone design values. The following presents an example on August 4, 2016, a day within the top ten highest model estimated MDA8 ozone concentrations at the Alsip / Village Garage monitor.

[14] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf

[15] Stanier, C. O., & et al. (2021, November). Overview of the Lake Michigan Ozone Study 2017. BAMS, 19.

In Figure 2 below, the black wind vectors are the wind fields used in the CAMx model. For clarity only every third grid cell is presented. The red vectors are the hourly observed wind vectors from the MADIS archive. The hourly results from 1300 CDT through 1600 CDT are presented in these Figures. The observations clearly show a broad persistent land to lake flow along the western shoreline while the model shows a persistent lake to land flow in this same region during this same period. For this timeframe, when the model is estimating the highest ozone for the ozone season at this receptor, the model has the winds flowing from the lake to the shore while the observations are winds flowing from the shore to the lake.

Figure 2 demonstrates that observed winds (red arrows) are seen moving from land to lake along the western shoreline of Lake Michigan, typically associated with clearing events and lower ozone levels in areas in and around Chicago. In contrast, the model (black arrows) shows a lake to land flow, typically associated with higher model predicted ozone concentrations due to the higher reactive photochemistry over water bodies.

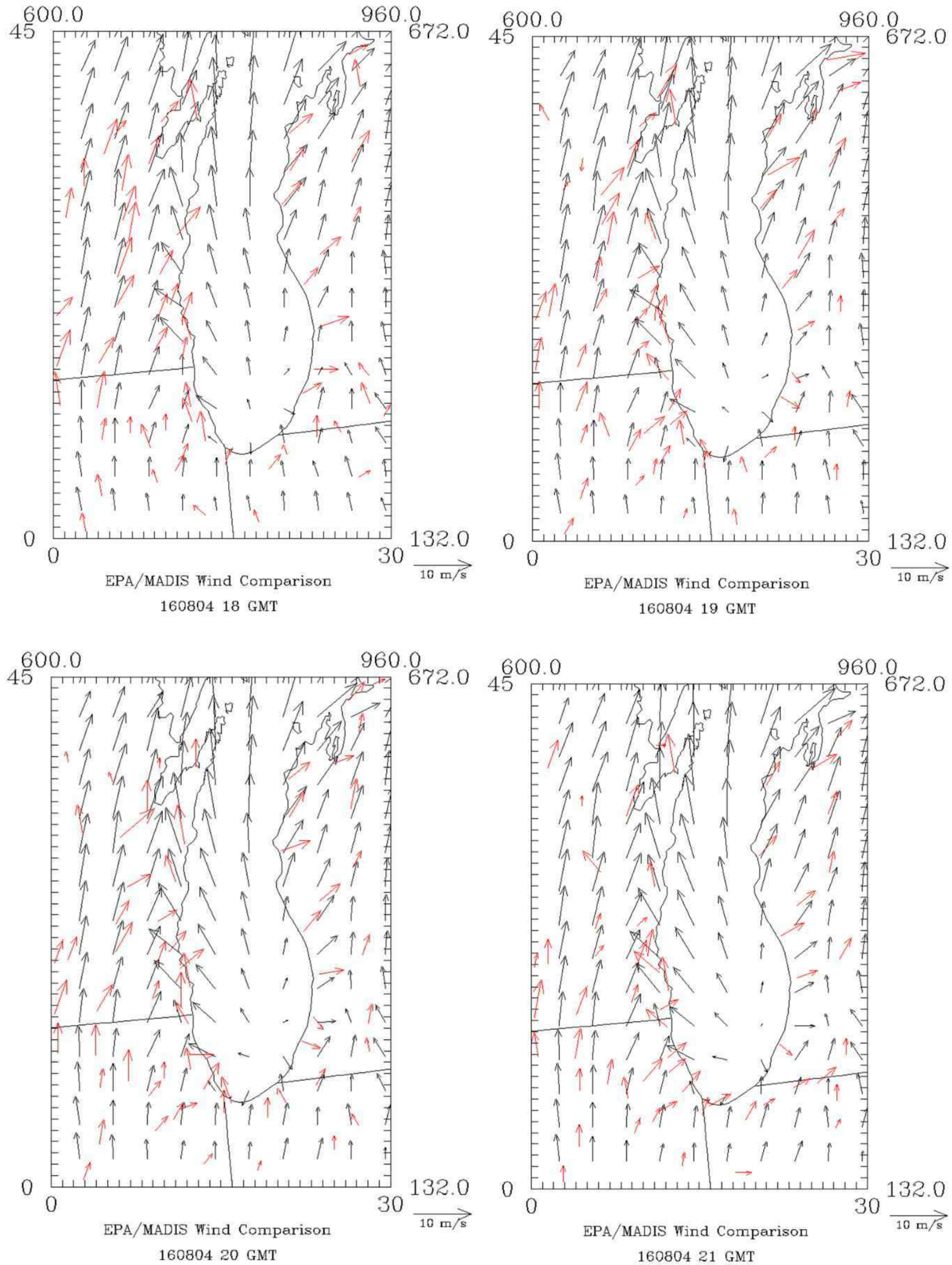

Figure 2. Model estimated (black) and observed (red) winds in the Lake Michigan area at 1300 CDT (top left), 1400 CDT (top right), 1500 CDT (bottom left), and 1600 CDT (bottom right) on August 4, 2016.

These large differences in observed and modeled wind directions are altering the concentration calculations as well as the source/receptor relationships (e.g., determining which sources are "upwind") of the Illinois monitors. As a result, the model cannot accurately reproduce the chemical processes involved with ozone formation. The erroneous modeled meteorological conditions fundamentally change the ozone formation chemistry and modeled source contributions as the chemical transport model predicts more emissions coming from the Chicago urban area than likely the case consistent with the observed wind fields.

When the model is having difficulty resolving fundamental flow patterns in this region with this grid size resolution, EPA needs to reconsider the merit of using the model with this configuration to determine nonattainment status in Step 1 as well as linked significant contributors at receptors in this region under Step 2. For these reasons, EPA must consider finer grid resolution modeling over the Lake Michigan domain to adequately capture ozone formation and significant contribution at receptors located on complex land-water interfaces because model evaluation shows that the model fails to adequately characterize ozone production at these monitors.

Absent a wholesale revision of EPA's modeling protocol, it is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

3. EPA is obligated to address VOC emissions as a critical factor that is influencing ozone nonattainment/maintenance monitors in Illinois

EPA's modeling fails to account for VOC-limited conditions in the Lake Michigan region. Recent information supports the conclusion that VOC-limited conditions in the regional are much more significant that EPA has assumed. This results in EPA's analysis overemphasizing upwind NOx contributions from Minnesota on ozone values at the Alsip/Village Garage monitor and an underemphasis on local VOC contributions, which can be more effectively used to control ozone.

In addition to grid size resolution and complex meteorology issues, modeling performed by EPA[16] and the LMOS 2017 study both showed a negative bias in predicted ozone concentrations in the Lake Michigan region. LMOS 2017 study researchers have experimented with increasing

[16] EPA-HQ-OAR-2021-0668-0099

anthropogenic VOC emissions and decreasing anthropogenic NOx emissions. These emission changes improved air quality model performance reducing the negative bias. VOC speciation and spatio-temporal release patterns should also be reviewed. This evaluation by the LMOS 2017 research scientists indicates there are significant errors in the quantity and speciation of the VOC/NOx emissions used in the EPA's air quality modeling platform to characterize state contribution to ozone in Step 2 of EPA's analyses linking these states to critical nonattainment monitors.

Several downwind nonattainment monitors in urban areas around Lake Michigan recently have been shown to be largely unresponsive to ozone reduction strategies consisting of regional interstate NOx control and that high ozone days in the region were predominantly VOC-limited in nature. This was demonstrated in multiple ozone episodes extensively evaluated in the Lake Michigan Air Directors Consortium (LADCO) Lake Michigan Ozone Study (LMOS) 2017 study[17] where ozone precursor measurements indicated relative increases in VOC concentrations with increases in ozone and where biogenic VOC increases outpaced those of anthropogenic VOC.

In contrast to the peer reviewed research resulting from the 2017 LMOS data collection effort, EPA recently documented its support for additional NOx controls in stating that its "review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[18] However, the current situation is that the modeling as conducted does not accurately characterize ozone levels on high ozone days, underpredicting by 10 + ppb, which is a huge error. Other studies indicate that, to better match actual conditions, the model needs less NOx and higher windspeeds at lower levels. The model is therefore demonstrating that less NOx means more ozone and higher ozone concentrations. That further means that, proportionally, the attribution of ozone to out of state NOx predicts a higher impact than is occurring.

The modeled VOC and NOx emission tracers in EPA's Anthropogenic Precursor Culpability Assessment (APCA) modeling can give a general indication of the VOC/NOx sensitivity, but EPA assigning definitive numerical values to that sensitivity provides inaccurate projections, especially using APCA that is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions. As documented in the CAMx v 7.10 User's Guide[19], "when ozone formation is due to biogenic VOC and anthropogenic NOx under

[17] https://www.ladco.org/wpcontent/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[18] 87 Fed. Reg. 20,076
[19] https://camx-wp.azurewebsites.net/Files/CAMxUsersGuide_v7.10.pdf, page 177.

VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NOx present. Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NOx sources and less ozone formation attributed to biogenic VOC sources." Here, it is believed that as applied in this case (with biogenic emissions as an uncontrollable source group), EPA has overestimated the efficacy of NOx controls on these receptors as modeled results have a bias toward attributing more ozone formed to NOx emissions than VOC emissions.

Furthermore, an independent review of EPA's own NOx and VOC contributions challenges the Agency's statement that "[o]ur analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NOX-limited, rather than VOC-limited."[20] This statement is based on all anthropogenic NOx and VOC emissions from all upwind states and is defined as having NOx emissions contribute to 80% or more of the ozone concentrations modeled at each receptor[21].

EPA further goes on to state that "[t]his review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[22]

Alpine's review of EPA's modeled NOx and VOC contributions, by upwind state, focusing on the future year modeled days used in each receptor's Step 2 linkage calculation provides a slightly different picture for monitors around Lake Michigan. As demonstrated in Table 5, of the top future year modeled days impacting significant contribution calculations at the Cook County, Illinois monitor with which Minnesota is linked, more than half of the days are shown to have NOx emission contributions from Illinois below the 80% threshold noted by EPA in determining NOx-limited regions. This is an indicator that on those days, and from anthropogenic sources from those states, VOC controls may demonstrate meaningful impact on ozone concentration reductions at this receptor.

Researchers at the University of Maryland (UMD) have also found in a study of chemical transport model results that by 2023, model predictions of ozone formed under VOC-limited conditions are substantial near the Long Island Sound and the Great Lakes. In a recent presentation[23], they document a source apportionment simulation, conducted with CAMx/APCA on future-year 2023 to determine the major contributing sources and states to air

[20] 87 Fed. Reg. 20053
[21] 87 Fed. Reg. 20076
[22] Id.
[23] https://www.cmascenter.org/conference/2021/slides/allen-northeast-ambient-ozone-2021.pdf

quality within non-attainment areas. Their findings indicate that ozone production under VOC-limited conditions is important at coastal locations near Long Island Sound and the Great Lakes.

		2023 O3	O3N / O3N+O3V Contribution						
Top Day	Date	(ppb)	All	IL	IN	MI	OH	TX	WI
1	07/25/16	70.922	82.4%	81.2%	83.4%	100.0%	-	72.7%	84.1%
2	07/18/16	70.682	69.4%	64.3%	75.6%	-	-	85.9%	67.1%
3	07/19/16	70.668	79.9%	76.7%	83.7%	90.5%	-	80.5%	89.2%
4	08/10/16	67.487	79.4%	70.0%	82.4%	90.4%	86.4%	90.3%	90.6%
5	07/26/16	66.803	80.8%	72.7%	84.0%	90.7%	-	-	90.8%
6	07/23/16	63.295	84.9%	81.2%	84.0%	66.7%	-	89.7%	85.2%
7	08/03/16	61.342	88.8%	84.0%	90.9%	90.4%	92.3%	94.2%	93.8%
8	06/18/16	59.494	86.7%	72.8%	89.4%	90.1%	91.0%	90.9%	89.5%
9	06/03/16	58.730	71.5%	63.2%	73.6%	58.8%	-	74.5%	78.0%
10	08/04/16	58.241	95.0%	92.5%	96.0%	94.7%	97.1%	96.4%	94.9%

Table 5. Modeled ozone contributions to Cook, Illinois monitor (170310001) by percent of emissions from anthropogenic NOx (O3N) compared to emissions from anthropogenic NOx and VOC (O3). Yellow cells indicate contributions of anthropogenic VOC emissions greater than EPA identified "NOx-limited" areas.

Figure 3 presents UMD's findings for model predictions of ozone formation under NOx limited conditions excluding the influence of boundary and initial conditions from the modeling input. As can be seen in these figures, regions around Lake Michigan demonstrate a significantly higher percentage of ozone formed by VOC (blue in color) compared to NOx than most of the eastern US. This observation is seen both on modeled days greater than 60 ppb and on the top ten days of the ozone season (days used in RRF and significant contribution calculations).

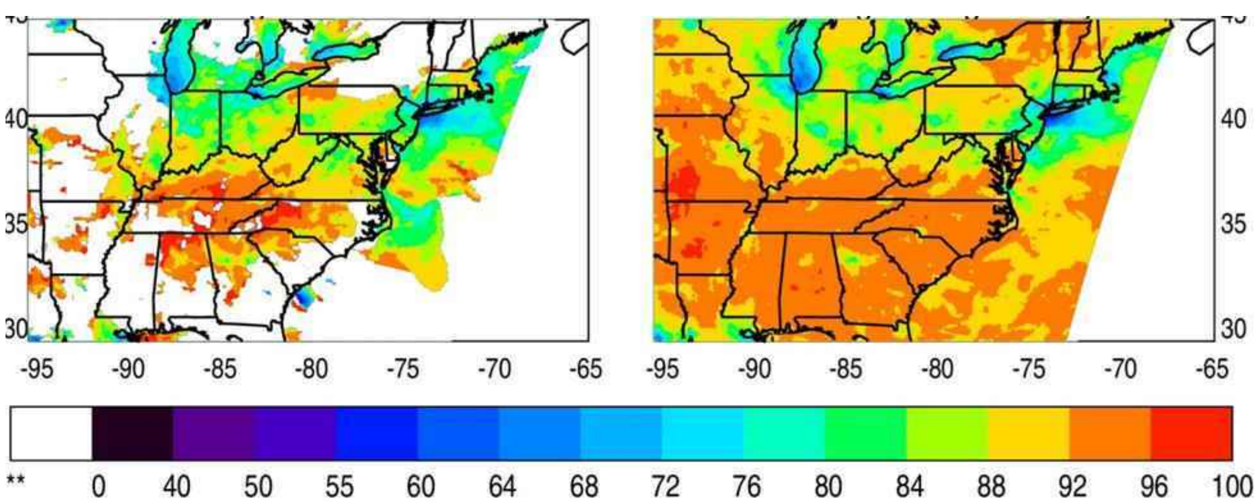

Figure 3. Percent of ozone formed under NOx-limited conditions excluding boundary and initial conditions on all days of MDA8 ozone > 60 ppb (left) and on top ten modeled days (right).

It is also noted that these estimates are a very conservatively high estimate of NOx limited conditions for these coastal areas. In addition to the previous comments highlighting that APCA is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions, the UMD analysis footnotes that the APCA run used to generate the results presented in Figure 3 suggests that model configuration led to an underestimation of the contribution of anthropogenic sources to ozone formation, especially during periods of VOC limited chemistry, and as is seen in Figure 3, in the Cook County, Illinois area.

As a result of these findings, EPA is obligated to address the concern that VOC emissions are a factor that is influencing ozone nonattainment and maintenance monitors in Illinois and elsewhere and that EPA determination of ozone nonattainment or maintenance in these areas may be inappropriate for significant contribution and upwind state linkage calculation. It is also our opinion that after review of VOC contribution and limited ozone reduction potential in Chicago and other noted areas, EPA may find that emission reduction plans may fail to justify regional NOx rules for monitors within these transitional and VOC-limited domains.

B. U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary.

EPA failed to give appropriate recognition of the merit of the MPCA SIP submitted on October 1, 2018, meeting the statutory deadline for submittal of interstate transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

Under the CAA, on April 1, 2019, MPCA's SIP was deemed to be complete since EPA did not act within the 6 months from the date the SIP was submitted. April 1, 2020, 12 months after the completeness date, was the deadline for EPA to have acted on the MPCA SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[24] In this regard, EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

It wasn't until February 22, 2022, three years and four months after submittal, that EPA finally assessed the Minnesota SIP submittal and proposed disapproval of the SIP[25] as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."

The EPA reiterated this assessment and issued a partial approval on February 13, 2023, in their final rule stating that "Although the EPA acknowledges that Minnesota's Step 3 analysis was insufficient in part because the State assumed it was not linked at Step 2, this is ultimately inadequate to support a conclusion that the State's sources do not interfere with maintenance of the 2015 ozone NAAQS in other states in light of more recent air quality analysis."[26]

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[24] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

[25] 87 Fed. Reg. 9838

[26] 88 Fed. Reg. 9357

1. EPA's Failure to Act

MPCA has been disadvantaged by EPA's delay in acting to approve or disapprove its 2015 Good Neighbor SIP, which was submitted to EPA on October 1, 2018. EPA published its proposed disapproval on February 22, 2022, and relied in part on newer, updated modeling performed by the EPA which was not available when MPCA submitted its revised SIP. On February 13, 2023, EPA published its final disapproval and again relied on even newer, updated modeling only released with the rule.

By delaying its final decision on Minnesota's submittal for nearly four and a half years, EPA moved the goal post for Minnesota—an act the DC Circuit rebuked in New York v. EPA, 964 F.3d 1214, 1223 (D.C. Cir. 2020). If EPA were to review and approve or disapprove SIPs within the timeframes required by the CAA, EPA would have conducted its review based on the same modeling and data that was available at the time the SIP was submitted and that has been documented in the sections above. EPA offers no indication that additional material information was available to EPA on April 1, 2020, when agency action on the Minnesota SIP was required that could justify disapproval of the Minnesota SIP.

Further, the updated modeling that EPA now offers to support a SIP review has not been adequately available to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval.

2. EPA has not developed any official guidance for states to follow in submitting a Good Neighbor SIP

The Good Neighbor SIP has been a required SIP element since the implementation of the 1997 8- hour ozone standard. In the intervening years, EPA has issued no official guidance for states to use in developing an approvable Good Neighbor SIP. It is unclear what standard or criteria EPA uses to determine approvability.

In its only direction on the subject, EPA released three 2018 memos that included modeling and discussion on potential flexibilities in approaches that could be used by states in developing their Good Neighbor SIPs. However, EPA has now disapproved MPCA's SIP which was based on EPA's own modeling results from the memo because it "does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."[27]

[27] 87 FR 9869

From the memos, the only concrete guidance states have been provided is the four-step framework. Applied appropriately in the MPCA SIP, this framework demonstrated that Minnesota was not significantly linked to any downwind nonattainment or maintenance monitor. Since MPCA used EPA's own modeling and four-step approach to prepare its SIP, the SIP was approvable at the time submitted and was approvable when EPA was required to act on the SIP on April 1, 2020.

3. EPA's ever-changing list of nonattainment and maintenance monitors moves the target for Minnesota without offering any basis to reject MPCA's original analysis.

As detailed earlier, MPCA's air quality projections based on the ozone modeling conducted by LADCO in October 2018 was corroborated by EPA's own contribution modeling released with the March 2018 flexibilities memorandum and that showed that Minnesota was not linked to any monitor designated as nonattainment or maintenance for the 2015 ozone NAAQS in 2023. In those two modeling studies, the Cook County, Illinois monitor now linked to Minnesota was calculated to be in attainment for the 2015 ozone NAAQS.

Table 6 provides the average and maximum projected design values from the LADCO modeling that supported the original MPCA iSIP and March 2018 EPA memo modeling for this monitor demonstrating modeled attainment at this location.

			LADCO Modeling		EPA March 2018 Memo	
AQS Site ID	State	County	2023 Average DV	2023 Maximum DV	2023 Average DV	2023 Maximum DV
170310001	Illinois	Cook	62.8	64.6	63.2	64.9

Table 6. LADCO and EPA 2023 ozone design values (ppb) for Minnesota linked Cook County, Illinois monitor from original MPCA SIP and March 2018 EPA memo modeling results.

EPA's proposed disapproval mentions new modeling conducted by EPA in the interim where this Illinois monitor is ultimately identified as a maintenance monitor. Table 7 below provides the average and maximum projected design values from these studies and from the final SIP disapproval for this monitor.

In the proposed SIP disapproval, EPA cites the "results of a prior round of 2023 modeling using the 2016v1 emissions platform which became available to the public in the fall of 2020 in the Revised CSAPR Update." [28] In this Revised CSAPR Update modeling, developed for use with the 2008 ozone NAAQS analyses, monitor 170310001 is identified as a maintenance monitor in

[28] Footnote 94, 87 FR 9869

EPA's results. In EPA's results published in the proposed SIP disapproval[29] and in the final SIP disapproval[30], EPA continued to identify this monitor as a maintenance monitor.

	EPA Revised CSAPR Update		EPA Proposed SIP Disapproval		EPA Final SIP Disapproval	
AQS Site ID	2023 Ave DV	2023 Max DV	2023 Ave DV	2023 Max DV	2023 Ave DV	2023 Max DV
170310001	68.4	72.2	69.6	73.4	68.2	71.9

Table 7. EPA 2023 ozone design values (ppb) for Cook County, Illinois monitor from EPA cited modeling results in proposed and final Minnesota SIP disapproval.

In our opinion, EPA should always rely on the best available modeling at the time that an analysis is conducted and results, whether in a SIP or other, are developed and submitted. In this case, EPA has failed to follow this process and instead continued to move the target and objectives for states that, in Minnesota's case, for over four years and four months had been waiting for a review of their "best available data and analysis".

4. Alternative 1 ppb significance threshold

Neither the LADCO modeling nor EPA modeling released with the March 2018 memorandum indicated that Minnesota would contribute over 1% of the NAAQS to any nonattainment or maintenance monitor in 2023. As a result, Minnesota did not think it necessary to consider using a 1 ppb threshold for significant contribution to downwind receptors, which EPA guidance offered as an option to States.

In the SIP disapproval, EPA further elaborates that following their receipt and review of forty-nine good neighbor SIPs for the 2015 ozone NAAQS, their experience was that no state relying on a 1 ppb threshold provided sufficient information and technical support to justify that an alternative threshold was reasonable[31]. EPA does not indicate how many of the reviewed SIPs used a 1 ppb threshold nor do they indicate on how many state SIPs they provided feedback, if any. They go on to state that this alternate 1 ppb threshold may also be politically inconsistent and impractical under the CAA[32].

As EPA not only failed to provide any feedback to Minnesota on its original October 1, 2018 SIP submittal until the February 22, 2022 proposed SIP disapproval, EPA has also failed to honor its March 2018 guidance[33] which was identified to specifically "*provide analytical information*

[29] Table 5, 87 FR 9868
[30] Table III.B-2, 88 FR 9351
[31] 87 FR 9843
[32] Footnote 33, 87 FR 9843
[33] https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf

regarding the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states to downwind receptors or the 2015 ozone NAAQS. It also interprets that information to make recommendation about what thresholds may be appropriate for use in state implementation plan (SIP) revisions addressing the good neighbor provision for that NAAQS."

Minnesota has been denied the opportunity to correct the model inputs that EPA uses as the basis for SIP Disapproval at the 1% threshold and denied the opportunity to update its SIP to take advantage of the 1 ppb threshold that EPA offers States an opportunity to justify in its guidance. While EPA continues to regenerate results based on updated emission modeling platforms and other associated information, states have been omitted from the process, denying them the chance to review updated information and to provide revisions to their SIPs to address those updates.

It is important to note that under all of EPA's cited modeling results, Minnesota contributes under the 1 ppb permitted to be considered from EPA's March 2018 guidance. Table 8 below shows that under none of EPA's four modeling platforms does Minnesota contribute over the 1 ppb threshold to the Cook County monitor.

			Minnesota Contribution (ppb) in 2023			
AQS Site ID	**State**	**County**	**EPA March 2018 Memo**	**EPA Revised CSAPR Update**	**EPA Proposed SIP Disapproval**	**EPA Final SIP Disapproval**
170310001	Illinois	Cook	0.76	0.79	0.97	0.85

Table 8. Minnesota contribution to Cook County, Illinois 2023 ozone design values from documented modeling platforms.

EPA's 2018 flexibility memos, including the opportunity for states to make recommendations to support alternate thresholds for significant contribution, remains an important tool for addressing unique State circumstances in developing their good neighbor SIPs. Disapproving the Minnesota SIP without affording the State an opportunity to utilize this flexibility is unreasonable and should be reconsidered.

C. The Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

1. Introduction

On October 1, 2018, the Minnesota Pollution Control Agency, after review and comment by EPA Region 5 staff, submitted to the U.S. Environmental Protection Agency a request for revision of Minnesota's State Implementation Plan[34].

The proposed SIP revision addressed Minnesota's responsibilities relating to the "Infrastructure" SIP (iSIP) requirements of sections 110(a)(l) and 110(a)(2) of the Clean Air Act (CAA), as they pertain to the National Ambient Air Quality Standard (NAAQS) for ozone, promulgated in 2015. The CAA requires states to submit an iSIP within three years of the EPA's issuance of a new NAAQS to demonstrate their continued ability to implement, maintain, and enforce the federal standards. The iSIP outlined the statutes, rules, and programs that enable Minnesota to ensure attainment of the 2015 ozone NAAQS. These statutes, rules, and programs had previously been reviewed and approved into Minnesota's iSIP, and the materials included with the iSIP demonstrate that the MPCA did not have further obligations under the iSIP requirements.

The MPCA submission utilized both EPA modeling released with a March 2018 flexibilities memorandum[35] and Lake Michigan Air Directors Consortium (LADCO) modeling results[36]. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

In this document we discuss both the technical and legal validity of MPCA's SIP and EPA's obligation to approve the SIP.

EPA's and LADCO's model projections, along with continuing decreases in the emissions and monitored levels of ozone precursors in Minnesota (nitrogen dioxide and volatile organic compounds), demonstrated that no additional controls or emissions limits were necessary to

[34] EPA-R05-OAR-2018-0689-0003

[35] https://www.epa.gov/interstate-air-pollution-transport/memo-and-supplemental-information-regarding-interstate-transport

[36] https://www.ladco.org/wp-content/uploads/Documents/Reports/TSDs/O3/LADCO_2015O3iSIP_TSD_13Aug2018.pdf

fulfill Minnesota's responsibilities under the good neighbor provisions for the 2015 ozone NAAQS.

On February 13, 2023, almost four and a half years after the original SIP submittal, EPA finalized a rule in connection with the Air Plan Disapprovals; Interstate Transport Requirements for the 2015 8-Hour Ozone National Ambient Air Quality Standards[37].

EPA notes in this final rule, that these disapprovals would not start a mandatory sanctions clock but rather would establish a 2-year deadline for EPA to promulgate a Federal Implementation Plan (FIP), unless EPA were to approve a subsequent SIP submittal that meets CAA requirements. EPA originally proposed a FIP to be finalized December 15, 2022, in complete disregard for the 2-year period allowed by the CAA for responding to any such SIP disapprovals[38]. This FIP[39] was signed by the Administrator on March 15, 2023, and is still awaiting publication in the Federal Register.

In 2018 EPA issued flexibility guidance for states to follow in development of 2015 ozone standard NAAQS God Neighbor SIPs (GNS). We specifically question how EPA's late disapproval contradicts this guidance.

2. MPCA's Modeling Approach

The modeling performed to support the SIP was performed by LADCO and except for the 2023 projected EGU emissions, was identical to the "EN" platform developed by EPA and followed EPA guidance[40] in preparation of technical material for SIP and SIP-related modeling. The EN platform was used by EPA in its March 2018 flexibility memorandum so that "[s]tates can use these data to develop their implementation plans to assure that emissions within their jurisdictions do not contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone standards in other states."

In our opinion, this platform was technically credible, and a SIP developed from these data should have been approvable by EPA at the time of submission in October 2018. The following sections present our opinions on specific technical aspects of MPCA modeling.

[37] Id.
[38] 87 Fed. Reg 20036
[39] https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf
[40] https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

Base Year

The base year for the MPCA modeling was 2011. 2011 was selected because of data availability and because EPA[41] had noted that 2011 meteorology in the Eastern U.S., including the upper Midwest, was warmer and drier that the climatic norm and represented typical conditions conducive to high observed ozone concentrations in the Midwest and Northeast U.S. It is Alpine's opinion that 2011 was an appropriate modeling year.

Model and Data Selection

This section introduces the models and data sources used in the MPCA. The selection methodology followed EPA's guidance for ozone regulatory modeling[42],[43],[44]. EPA's 2018 modeling guidance[45] lists several criteria for model selection that are paraphrased as follows (pp. 24-27):

- It should not be proprietary;
- It should have received a scientific peer review;
- It should be demonstrated to be applicable to the problem on a theoretical basis;
- It should be used with data bases which are available and adequate to support its application;
- It should be shown to have performed well in past modeling applications;
- It should be applied consistently with an established protocol on methods and procedures;
- It should have a user's guide and technical description;
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable; and

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[41] Air Quality Modeling Technical Support Document for the 2008 Ozone NAAQS Cross-State Air Pollution Rule Proposal. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2015-11/documents/air_quality_modeling_tsd_proposed_rule.pdf

[42] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Research Triangle Park, NC. EPA-454/B-07-002. April, 2007. (http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf).

[43] Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, RTP, NC. December 3, 2014. (http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf).

[44] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[45] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

- When other criteria are satisfied, resource considerations may be important and are a legitimate concern.

It is Alpine's opinion that the models chosen for the MPCA modeling met these criteria and were appropriate for use in the SIP.

Meteorological Modeling

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs[46],[47],[48]. The Advanced Research WRF (ARW) version of WRF was used in the MPCA modeling study. It features multiple dynamical cores, a 3-dimensional variational (3DVAR) data assimilation system, and a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from meters to thousands of kilometers. The effort to develop WRF has been a collaborative partnership, principally among the National Center for Atmospheric Research (NCAR), the National Oceanic and Atmospheric Administration (NOAA), the National Centers for Environmental Prediction (NCEP) and the Forecast Systems Laboratory (FSL), the Air Force Weather Agency (AFWA), the Naval Research Laboratory, the University of Oklahoma, and the Federal Aviation Administration (FAA). WRF allows researchers the ability to conduct simulations reflecting either real data or idealized configurations. WRF provides operational forecasting a model that is flexible and efficient computationally, while offering the advances in physics, numerics, and data assimilation contributed by the research community.

WRF is publicly available, has full documentation and has demonstrated success in simulating meteorological conditions in the Upper Midwest.

[46] Skamarock, W. C. 2004. Evaluating Mesoscale NWP Models Using Kinetic Energy Spectra. *Mon. Wea. Rev.*, Volume 132, pp. 3019-3032. December, 2004. (http://www.mmm.ucar.edu/individual/skamarock/spectra_mwr_2004.pdf).

[47] Skamarock, W. C. 2006. Positive-Definite and Monotonic Limiters for Unrestricted-Time-Step Transport Schemes. *Mon. Wea. Rev.*, Volume 134, pp. 2241-2242. June. (http://www.mmm.ucar.edu/individual/skamarock/advect3d_mwr.pdf).

[48] Skamarock, W. C., J. B. Klemp, J. Dudhia, D. O. Gill, D. M. Barker, W. Wang and J. G. Powers. 2005. A Description of the Advanced Research WRF Version 2. National Center for Atmospheric Research (NCAR), Boulder, CO. June. (http://www.mmm.ucar.edu/wrf/users/docs/arw_v2.pdf)

MPCA used the U.S. EPA 2011 WRF data for this study[49]. The U.S. EPA used version 3.4 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2011 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation (FDDA) configuration are detailed in the U.S. EPA 2008 Transport Modeling technical support document[50]. U.S. EPA prepared the WRF data for input to CAMx with version 4.3 of the WRFCAMx software.

It is Alpine's opinion that the U.S. EPA WRF 3.4 meteorological modeling was appropriate for use in the MPCA SIP.

Initial and Boundary Conditions

MPCA used 2011 initial and boundary conditions for CAMx generated by the U.S. EPA from the GEOS-Chem Global Chemical Transport Model[51]. EPA generated hourly, one-way nested boundary conditions (i.e., global-scale to regional-scale) from a 2011 2.0 degree x 2.5 degree GEOS-Chem simulation. Following the convention of the U.S. EPA O3 transport modeling, year 2011 GEOS-Chem boundary conditions were used by LADCO for modeling 2023 air quality with CAMx.

It is Alpine's opinion that the U.S. EPA GEOS-Chem derived initial and boundary conditions were appropriate for use in the MPCA SIP.

Emissions

The 2023 emissions data for the MPCA SIP were based on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform[52]. U.S. EPA generated this platform for their final assessment of Interstate Transport for the 2008 O3 NAAQS. Updates from earlier 2011-based emissions modeling platforms included a new engineering approach for forecasting emissions from Electricity Generating Units (EGUs). LADCO replaced the EGU emissions in the U.S. EPA EN

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[49] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[50] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

[51] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[52] US EPA. 2017. Technical Support Document: Additional Updates to Emissions Inventories for the Version 6.3 Emissions Modeling Platform for the Year 2023. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-11/documents/2011v6.3_2023en_update_emismod_tsd_oct2017.pdf

platform with 2023 EGU forecasts estimated with the ERTAC EGU Tool version 2.7[53]. ERTAC EGU 2.7 integrates state-reported information on EGU operations and forecasts as of May 2017. The MPCA believes "power sector emissions forecasts must address economic factors, preserve system reliability, and include controls or emission reduction measures justified through some legal framework. It is our understanding that the engineering analysis used by EPA to project EGU emissions to 2023 (version EN of the modeling platform) does not comply with these key requirements. The ERTAC estimates incorporate the key requirements."[54]

In March 2018 U.S. EPA released it flexibilities memo that described a series of flexibilities that states could consider in developing Good Neighbor SIPs for the 2015 ozone NAAQS. The "[u]se of alternative power sector modeling consistent with EPA's emissions inventory guidance" is presented in the Analytics section of EPA's March 2018 memo as a flexibility to consider in preparing a Good Neighbor SIP. This flexibility supports LADCO's use of the ERTAC EGU model for projecting EGU emissions to 2023. MPCA considers the emissions projections from ERTAC EGU to be more representative of the sources in the Midwest and Northeast than the approach used by U.S. EPA in their 2023 EN modeling platform. As ERTAC EGU is developed in collaboration between regional and state air planning agencies, it includes algorithms and data that have been reviewed by many of the states impacted by interstate O3 transport in the Midwest and Eastern U.S.

Preparation of the emissions data to support photochemical models is a very complicated process that entails the use of a number of different "sub-models" to prepare different emission segments.

Sparse Matrix Operator Kernel Emissions (SMOKE)

The Sparse Matrix Operator Kernel Emissions (SMOKE) is an emissions modeling system that generates hourly gridded speciated emission inputs of mobile, non-road, area, point, fire and biogenic emission sources for PGMs[55],[56]. As with most "emissions models," SMOKE is principally an emission processing system and not a true emissions modeling system in which emissions estimates are simulated from "first principles." This means that, except for mobile and biogenic sources, its purpose is to provide an efficient, modern tool for converting an existing base emissions inventory data that is typically at the county or point source level into

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[53] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[54] EPA-R05-OAR-2018-0689-0003

[55] Coats, C.J. 1995. Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, MCNC Environmental Programs, Research Triangle Park, NC.

[56] UNC. 2018. SMOKE v4.6 User's Manuel. University of North Carolina at Chapel Hill, Institute for the Environment. Chapel Hill, North Carolina. September 24. (https://www.cmascenter.org/smoke/documentation/4.6/manual_smokev46.pdf).

the hourly gridded speciated formatted emission files required by a Photochemical Grid Model (PGM), like CAMx. SMOKE was used to prepare emission inputs for non-road mobile, non-point (area) and point sources. SMOKE performs three main function to convert emissions to the hourly gridded emission inputs for a PGM: (1) spatial allocation, spatial allocates county-level emissions to the PGM model grid cells typically using a surrogate distribution (e.g., population); (2) temporal allocation, allocates annual emissions to time of year (e.g., monthly or seasonally) and day-of-week (typically weekday, Saturday and Sunday); and (3) chemical speciation, maps the emissions to the species in the chemical mechanism used by the photochemical grid model, most important for VOC and $PM_{2.5}$ emissions.

The primary emissions modeling tool used to create the air quality model-ready emissions was the SMOKE modeling system version 3.7 which was used to create emissions files for a 12-km national grid "12US2" that includes all of the contiguous states.

It is Alpine's opinion that the SMOKE emissions model together with the other EPA emissions was appropriate for use in the MPCA SIP.

Motor Vehicle Emissions Simulator (MOVES)

The motor vehicle emissions were prepared by U.S. EPA using the MOVES 2014a emissions model[57],[58],[59]. MOVES 2014a was the most up to date released motor vehicle emissions processor at the time of the MPCA SIP submission and it is Alpine's opinion that the U.S. EPA MOVES 2014a emissions were appropriate for use in the MPCA SIP.

Eastern Regional Technical Advisory Committee EGU Model

The Eastern Regional Technical Advisory Committee (ERTAC) EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emissions projections. States needed a transparent model that was numerically stable and did not produce dramatic changes to the emissions forecasts with small changes in inputs. A key feature of the model

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[57] EPA. 2014a. Motor Vehicle Emissions Simulator (MOVES) – User Guide for MOVES2014. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-055). July. (http://www.epa.gov/oms/models/moves/documents/420b14055.pdf).

[58] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

[59] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

includes data transparency; all of the inputs to the model are publicly available. The code is also operationally transparent and includes extensive documentation, open-source code, and a diverse user community to support new users of the software.

Operation of the model is straightforward given the complexity of the projection calculations and inputs. The model imports base year Continuous Emissions Monitoring (CEM) data from U.S. EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off-peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve capacity, generates quality assurance reports, and converts the outputs to SMOKE ready modeling files.

ERTAC EGU has distinct advantages over other growth methodologies because it can generate hourly future year estimates which are key to understanding ozone episodes. The model does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Full documentation for the ERTAC Emissions model and 2.7 simulations are available through the MARAMA website[60].

Differences between the EPA and ERTAC EGU emissions forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions. The U.S. EPA EGU forecast used in the 2023 EN modeling used CEM data available through the end of 2016 and comments from states and stakeholders received through April 17, 2017[61]. ERTAC EGU 2.7 used CEM data from 2011 and state-reported changes to EGUs through May 2017. The ERTAC EGU 2.7 emissions used for the modeling represented the best available information on EGU forecasts for the Midwest and Eastern U.S. available during Spring-early Summer 2018.

The “consideration of state-specific information in identifying sources [e.g., electric generating units (EGUs) and non-EGUs] and controls” is one of the potential approaches in EPA’s March 2018 flexibilities memorandum. The use of the ERTAC EGU tool falls squarely within the parameters of this documented flexibility and it is Alpine’s opinion that MPCA’s used of EGU emission projections from this model were appropriate in the MPCA SIP.

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[60] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[61] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

BEIS

Biogenic emissions were computed by U. S. EPA based on the same version of the 2011 meteorology data used for the air quality modeling and were developed using the Biogenic Emission Inventory System version 3.61 (BEIS3.61) within SMOKE. The landuse input into BEIS3.61 is the BELD version 4.1 which is based on an updated version of the USDA-USFS Forest Inventory and Analysis (FIA) vegetation speciation-based data from 2001 to 2014 from the FIA version 5.1.

It is Alpine's opinion that the U.S. EPA application of the BEIS model was appropriate for use in the MPCA SIP.

3. Air Quality Modeling

The MPCA modeling used the Comprehensive Air-quality Model with Extensions (CAMx) air quality model[62]. CAMx is a state-of-science "One-Atmosphere" multi-scale photochemical grid model (PGM) capable of addressing ozone, particulate matter (PM), visibility and acid deposition at regional, urban and local scale typically for periods of a year. CAMx is a publicly available open-source computer modeling system for the integrated assessment of gaseous and particulate air pollution. Built on today's understanding that air quality issues are complex, interrelated, and reach beyond the urban scale, CAMx is designed to (a) simulate air quality over many geographic scales, (b) treat a wide variety of inert and chemically active pollutants including ozone, inorganic and organic $PM_{2.5}$ and PM_{10} and mercury and toxics, (c) provide source-receptor, sensitivity, and process analyses and (d) be computationally efficient and easy to use.

The U.S. EPA has approved the use of CAMx for numerous ozone and PM State Implementation Plans throughout the U.S. and has used this model to evaluate regional mitigation strategies including those for most recent national transport rules, such as the Cross-State Air Pollution Rule (CSAPR), CSAPR Update, and the modeling used in justification of denial of the MPCA SIP. The MPCA used Version 6.4, which was released in December 2016. Unlike some of EPA's previous ozone modeling guidance that specified a particular ozone model (e.g., EPA 1991 Guidance[63]) or that specified the Urban Airshed Model (UAM)[64], the EPA now recommends that

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[62] User's Guide: Comprehensive Air Quality Model with Extensions version 6.40. Novato, CA. http://www.camx.com/files/camxusersguide_v6-40.pdf

[63] Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-hr Ozone NAAQS". U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. May.

[64] User's Guide for the Urban Airshed Model. Volume I: User's Manual for UAM (CB-IV) prepared for the U.S. Environmental Protection Agency (EPA-450/4-90-007a). Systems Applications International, San Rafael, CA.

models be selected for ozone SIP studies on a "case-by-case" basis. The latest EPA ozone guidance[65] (pp. 24) explicitly mentions the CAMx PGMs as one of the most commonly used PGMs that would satisfy EPA's selection criteria but notes that this is not an exhaustive list and does not imply that it is "preferred" over other PGMs that could also be considered and used with appropriate justification.

The CAMx model is updated regularly to both update the science in the model and to address coding errors (bugs) in the code. CAMx 6.5 was released at the end of April 2018, approximately 6 months prior to submission the MPCA SIP submission. It is customary for regulatory modeling to "freeze" the model version during the modeling process to keep the modeling on schedule.

It is Alpine's opinion that the CAMx 6.4 air quality model along with the EPA EN platform with 2023 EGU's updated to include ERTAC was appropriate for use in the MPCA SIP.

4. Model Performance

MPCA relied on the model performance evaluation (MPE) conducted by the U.S. EPA on the modeling platform that we used for this study[66] to establish validity in the modeling platform. In addition to the MPE for the base year CAMx simulation, the U.S. EPA reported full MPE results for the 2011 WRF modeling[67] used in the CAMx simulations.

It is Alpine's opinion that the EPA WRF and CAMx performance evaluations showed adequate performance and that the modeling was appropriate for use in the MPCA SIP.

5. Source Apportionment

MPCA used the CAMx Anthropogenic Precursor Culpability Assessment (APCA) tool to calculate emissions tracers for identifying upwind sources of ozone at downwind monitoring sites. MPCA

[65] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[66] US EPA. 2016. Air Quality Modeling Technical Support Document for the 2015 Ozone NAAQS Preliminary Interstate Transport Assessment. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-01/documents/aq_modeling_tsd_2015_o3_naaqs_preliminary_interstate_transport_assessmen.pdf

[67] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

used the APCA technique because it more appropriately associates ozone formation to anthropogenic sources than the CAMx Ozone Source Apportionment Technique (OSAT). If any anthropogenic emissions are involved in a reaction that leads to ozone formation, even if the reaction occurs with biogenic VOC or NOx, APCA tags the ozone as anthropogenic in origin.

The APCA source apportionment tool has a robust theoretical basis and a long application history and it is our opinion that the APCA tool is appropriate for identifying upwind sources of ozone at downwind monitoring sites.

6. Interstate Transport Provisions – Section 110(a)(2)(D)

This section of the CAA requires SIPs to have provisions prohibiting sources from emitting air pollutants in amounts that would contribute significantly to nonattainment or interfere with maintenance in any other state. These interstate transport requirements are often referred to as "good neighbor SIPs". The analyses conducted both by LADCO and EPA to support the 2015 ozone good neighbor SIPs show Minnesota does not contribute significantly to air quality problems in any downwind nonattainment or maintenance area. Therefore, no additional controls or emissions limits were required to fulfill Minnesota's good neighbor obligations.

On March 27, 2018, the EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". EPA's Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

EPA identifies a four-step framework in the Memo, intended to guide states on how to go about developing good neighbor SIPs:

1. Identify downwind air quality problems;
2. Identify upwind states that contribute enough to those downwind air quality problems to warrant further review and analysis;
3. Identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems; and
4. Adopt permanent and enforceable measures needed to achieve those emissions reductions.

In Step 1, EPA identifies monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS in the 2023 analytic year. Where EPA's analysis shows that a site does

not fall under the definition of a nonattainment or maintenance receptor, that site is excluded from further analysis under EPA's 4-step interstate transport framework. For sites that are identified as a nonattainment or maintenance receptor in 2023, we proceed to the next step of our 4-step interstate transport framework by identifying the upwind state's contribution to those receptors.

In Step 2, EPA quantifies the contribution of each upwind state to each receptor in the 2023 analytic year. The contribution metric used in Step 2 is defined as the average impact from each state to each receptor on the days with the highest ozone concentrations at the receptor based on the 2023 modeling. If a state's contribution value does not equal or exceed the threshold of 1 percent of the NAAQS (i.e., 0.70 ppb for the 2015 ozone NAAQS), the upwind state is not ''linked'' to a downwind air quality problem, and EPA, therefore, concludes that the state does not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in the downwind states.

Comparably, in MPCA's SIP submission, they include LADCO's modeling which additionally follows the same transport framework and is corroborated by EPA's modeling with the data released with the March 2018 memo.

Step 1 - 2023 Air Quality Projections

MPCA's reported air quality projections[68] submitted with their SIP were based on the ozone modeling conducted by LADCO. The result of this LADCO 2023 modeling, using methods utilized by EPA and shown in Table 9 below, forecasted that no downwind monitors in the Midwest or Northeast would be nonattainment for the 2015 O3 NAAQS.

[68] Data source Table 5, Attachment 1, EPA-R05-OAR-2018-0689-0003

			LADCO 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	67.2	69.4	78.0	80.0
90013007	Fairfield	CT	67.8	71.6	84.3	89.0
90019003	Fairfield	CT	69.6	72.4	83.7	87.0
90099002	New Haven	CT	67.9	70.5	85.7	89.0
240251001	Harford	MD	69.4	71.8	90.0	93.0
260050003	Allegan	MI	67.1	69.8	80.3	83.0
261630019	Wayne	MI	67.7	69.7	78.7	81.0
360810124	Queens	NY	67.5	69.2	70.0	71.0
361030002	Suffolk	NY	69.8	71.3	83.3	85.0
550790085	Milwaukee	WI	62.1	65.1	78.3	82.0
551170006	Sheboygan	WI	69.3	71.5	84.3	87.0

Table 9. LADCO 2023 ozone design values at EPA identified nonattainment and maintenance monitors in the Midwest and Northeast.

EPA's own modeling[69], released with the March 2018 platform, shown in Table 10, and designed to be used by states in development of their ozone transport SIPs, indicated that in the Midwest or Northeast, two downwind monitors in Fairfield, Connecticut (monitors 90013007 and 90019003), a monitor in Suffolk, New York (36103002), and monitors in Milwaukee (550790085) and Sheboygan (551170006), Wisconsin would be in nonattainment for the 2015 ozone NAAQS.

			EPA 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	68.9	71.2	80.3	83.0
90013007	Fairfield	CT	71.0	75.0	84.3	89.0
90019003	Fairfield	CT	73.0	75.9	83.7	87.0
90099002	New Haven	CT	69.9	72.6	85.7	89.0
240251001	Harford	MD	70.9	73.3	90.0	93.0
260050003	Allegan	MI	69.0	71.7	82.7	86.0
261630019	Wayne	MI	69.0	71.0	78.7	81.0
360810124	Queens	NY	70.2	72.0	78.0	80.0
361030002	Suffolk	NY	74.0	75.5	83.3	85.0
550790085	Milwaukee	WI	71.2	73.0	80.0	82.0
551170006	Sheboygan	WI	72.8	75.1	84.3	87.0

Table 10. EPA 2023 ozone design values at nonattainment and maintenance monitors in the Midwest and Northeast.

[69] https://www.epa.gov/sites/default/files/2018-05/updated_2023_modeling_dvs_collective_contributions.xlsx

An additional six monitors in Connecticut (90010017 and 90099002), Maryland (240251001), Michigan (260050003 and 261630019), and New York (360810124) would be considered maintenance monitors in the projection.

In neither the LADCO nor EPA modeling cited in MPCA's SIP revision submission were the two Cook County, Illinois monitors (170314201 and 170310076) from EPA's SIP denial NPR, or the single monitor from EPA's final SIP disapproval action, identified as either nonattainment or maintenance monitors in the 2023 projections.

Step 2 - Significant Contribution to Downwind States

EPA has previously determined that a state contribution to downwind air quality problems below one percent of the applicable NAAQS is insignificant. This screening method was used in previous good neighbor SIP approvals, and other regulatory actions including (most notably) the Cross-State Air Pollution Rule (CSAPR), and the CSAPR update for the 2008 ozone NAAQS and 2012 NAAQS for particulate matter less than 2.5 micrometers in diameter (PM2.5). The one percent screening method was developed through several previous federal notice and comment rulemakings. One percent of the 2015 ozone NAAQS (70 ppb) is 0.70 ppb. Therefore, any state that contributes less than 0.70 ppb to a projected nonattainment or maintenance area in another state is not culpable for those air quality problems.

EPA and LADCO applied the Anthropogenic Precursor Culpability Analysis (APCA) technique in CAMx to identify upwind states culpable for downwind ozone air quality problems. The method accounts for anthropogenic nitrogen oxides (NO_x) and volatile organic carbon (VOC) emissions from all sources in each upwind state affecting projected 2023 ozone concentrations at each downwind air quality monitoring site designated a nonattainment or maintenance receptor. EPA and LADCO conducted the culpability analysis for the period May 1 through September 30, using the 2023 future emission estimates and 2011 meteorology.

Both LADCO and EPA analyses[70] conclude Minnesota is not culpable for ozone nonattainment, or interference with maintenance, in any downwind states. As shown in Table 11, prepared using data from MPCA's SIP[71], LADCO's analysis shows a maximum contribution of 0.45 ppb to the identified maintenance monitors, less than the 0.70 ppb identified as 1% of the NAAQS (70 ppb). EPA's analysis[72] (Table 12) indicates Minnesota contributes most to Milwaukee, Wisconsin monitor site 550790085. At a concentration of 0.40 ppb, this contribution is roughly equal to 0.57% of the 2015 ozone NAAQS.

[70] Data source Table 2, EPA-R05-OAR-2018-0689-0003
[71] Id.
[72] Id.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	67.2	69.4	0.17
90013007	Fairfield	CT	67.8	71.6	0.15
90019003	Fairfield	CT	69.6	72.4	0.11
90099002	New Haven	CT	67.9	70.5	0.16
240251001	Harford	MD	69.4	71.8	0.12
260050003	Allegan	MI	67.1	69.8	0.11
261630019	Wayne	MI	67.7	69.7	0.30
360810124	Queens	NY	67.5	69.2	0.16
361030002	Suffolk	NY	69.8	71.3	0.16
550790085	Milwaukee	WI	62.1	65.1	0.45
551170006	Sheboygan	WI	69.3	71.5	0.27

Table 11. LADCO 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	68.9	71.2	0.17
90013007	Fairfield	CT	71.0	75.0	0.15
90019003	Fairfield	CT	73.0	75.9	0.14
90099002	New Haven	CT	69.9	72.6	0.19
240251001	Harford	MD	70.9	73.3	0.13
260050003	Allegan	MI	69.0	71.7	0.11
261630019	Wayne	MI	69.0	71.0	0.31
360810124	Queens	NY	70.2	72.0	0.17
361030002	Suffolk	NY	74.0	75.5	0.18
550790085	Milwaukee	WI	71.2	73.0	0.40
551170006	Sheboygan	WI	72.8	75.1	0.28

Table 12. EPA 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

For the reasons set forth in this section, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 2018 was technically adequate and appropriate for the purpose it was intended and followed all available EPA guidance on preparing technical modeling for SIP and SIP-related analyses.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted.

D. Summary of Conclusions

For the reasons set forth in this document, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 1, 2018 was technically adequate and appropriate for the purpose it was intended and should have been approved by EPA at the time of submission. It is further our opinion that decisions made by EPA to compare MPCA's original submitted modeling to recently updated modeling, developed by EPA over four years and four months later than the original Oct 2018 submission, are inconsistent with EPA precedent.

It is our opinion that in the absence of inclusion of Minnesota's and other stakeholder's valid emission modeling platform revision submissions, as requested by EPA, and multiple reruns of the air quality in both the base year (2016) and projection year (2023) simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change nonattainment designations and linked significance using an updated platform and needs to be considered before making any final decision on denial of MPCA's SIP.

It is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

It is our opinion that the most recent modeling cited by EPA and used to justify the linkage of Minnesota to one downwind maintenance monitors in Cook County, Illinois has technical issues as it relates to that linked monitor which is located in a complex land-water interface and may require finer grid resolution modeling to adequately capture ozone formation and significant contribution, and that EPA must address the impact of VOC emissions in influencing ozone formation at monitors in Illinois.

It is our opinion that EPA has failed to follow the process by relying on the best available modeling at the time that an analysis is conducted, and results are developed and submitted. Instead, EPA continues to move the target and objectives for states that, in Minnesota's case, for over four years had been waiting for a review of their "best available data and analysis".

It is our opinion that EPA should not have used any updated modeling to support a SIP review while not providing the opportunity for that data to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval and that any modeling beyond what was conducted in the original SIP submittal was ancillary to the approval process. However, should EPA decide not to review MPCA's SIP revision on its merit, Alpine recommends that EPA withdraw the SIP disapproval in favor of correcting the technical errors that have been identified in its analysis and to propose an appropriate opportunity for Minnesota to address any deficiencies EPA may find in Good Neighbor Plans implementing the 2015 ozone NAAQS.

It is our opinion that EPA's 2018 flexibility memo has become so instrumental to states in developing their good neighbor SIPs, that EPA's decision to disallow the flexibilities that they themselves outlined in guidance, is unreasonable and should be reconsidered.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted. It is our opinion that the original MPCA SIP was and is approvable.

E. Minnesota 2015 Ozone SIP Timeline

October 1, 2015 – EPA finalized the revised 2015 ozone NAAQS. Pursuant to CAA section 110(a)(1), "each state shall . . . submit to the Administrator, within 3 years. . .after promulgation of a [primary NAAQS] (or any revision thereof) a plan which provides for implementation, maintenance, and enforcement of such primary standard. . ." CAA section 110(a)(2)(D)(i)(I) requires such SIPs to "contain adequate provisions prohibiting . . .any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, and other State with respect to such NAAQS.

March 27, 2018 - EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". EPA's Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

October 1, 2018 - Minnesota Pollution Control Agency (MPCA) submitted a SIP revision to address CAA Section 110(a)(2)(D)(i)(I) on October 1, 2018 .[73] The submission met the statutory deadline for submittal the interest transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

April 1, 2019 – This is 6 months after EPA received the Minnesota SIP submission and is the date that the CAA deems the Minnesota submittal to have been complete since EPA did not take action otherwise.

September 13, 2019 - The D.C. Circuit issued a decision in *Wisconsin v. EPA*, remanding the CSAPR Update to the extent that it failed to require upwind states to eliminate their significant

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[73] **Completeness Finding** - Pursuant to the CAA Section 110(k)(1)(B) "Within 60 days of the Administrator's receipt of a plan or plan revision, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria established pursuant to subparagraph (A) have been met. Any plan or plan revision that a State submits to the Administrator, and that has not been determined by the Administrator (by the date 6 months after receipt of the submission) to have failed to meet the minimum criteria established pursuant to subparagraph (a), shall on that date be deemed by operation of law to meet such minimum criteria."

contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). 938 F.3d at 313.

April 1, 2020 – This is 12 months after the completeness date and is the deadline for EPA to have acted on the MN SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[74]

May 19, 2020 - the D.C. Circuit issued a decision in *Maryland v. EPA* that cited the Wisconsin decision in holding that EPA must assess the impact of interstate transport on air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for EPA's denial of a petition under CAA section 126(b). Maryland v. EPA, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020). The court noted that "section 126(b) incorporates the Good Neighbor Provision," and, therefore, "EPA must find a violation [of section 126] if an upwind source will significantly contribute to downwind nonattainment at the next downwind attainment deadline. Therefore, the agency must evaluate downwind air quality at that deadline, not at some later date." Id. at 1204 (emphasis added). EPA interprets the court's holding in Maryland as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date, which is now the Moderate area attainment date under CAA section 181 for ozone nonattainment. The Moderate area attainment date for the 2015 ozone NAAQS is August 3, 2024. At the time of the statutory deadline to submit interstate transport SIPs (October 1, 2018), many states relied upon EPA modeling of the year 2023, and no state provided an alternative analysis using a 2021 analytic year (or the prior 2020 ozone season). However, EPA must act on SIP submittals using the information available at the time it takes such action. In this circumstance, EPA does not believe it would be appropriate to evaluate states' obligations under CAA section 110(a)(2)(D)(i)(I) as of an attainment date that is wholly in the past, because the Agency interprets the interstate transport provision as forward looking. See 86 FR at 23074; see also Wisconsin, 938 F.3d at 322. Consequently, in this proposal EPA will use the analytical year of 2023 to evaluate each state's CAA section 110(a)(2)(D)(i)(I) SIP submission with respect to the 2015 ozone NAAQS.

May 12, 2021 – Downwinders at Risk, et al filed Case No. 21 Civ. 21 Civ 3551 asserting that EPA failed to undertake certain non-discretionary duties under the CAA.

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[74] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

February 22, 2022 - EPA assessed the Minnesota submittal and on February 22, 2022 (3 years, 4+ months after submittal) the agency proposed denial of the Minnesota SIP as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state. Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838 (Feb. 22, 2022).

February 28, 2022 – EPA and Downwinders et al established in a Consent Decree entered into on 1/12/2022 that if EPA proposed a full or partial denial of the Minnesota SIP EPA shall have until December 15, 2022 to sign a final action. Note this is a settlement and does not erase the fact that EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

April 30, 2022 – EPA and Downwinders, et established in a Consent Decree entered into on 1/12/2022 that required EPA to sign for publication final rulemaking on April 30, 2022 to approve, disapprove, and conditionally approve the Minnesota SIP submissions for the 2015 ozone NAAQS.

May 22, 2022 – EPA proposed to approve most elements of the Minnesota October 1, 2018 submission intended to address all applicable infrastructure requirements for the 2015 NAAQS. (87 FR 31462).

July 29, 2022 – EPA approved most elements of the Minnesota October 1, 2018 SIP submission from Minnesota regarding infrastructure requirements for the 2015 ozone NAAQS. EPA did not act on the interstate transport requirements and visibility impairments requirements. (87 FR 45663).

December 8, 2022 – EPA and Downwinders et al filed a Joint Motion of Stipulated Extension of Consent Decree deadlines that provided the following schedule.

December 15, 2022 – Former agreed upon deadline by Downwinders for EPA to act on Minnesota SIP, but this deadline was moved by agreement to January 31, 2022.

January 31, 2023 - deadline to sign final action on Minnesota SIP pursuant to agreed upon extension of Downwinders Consent Decree.

February 13, 2023 – EPA publishes final disapproval of State Implementation Plan (SIP) submissions for 19 states, including Minnesota. Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336.

March 15, 2023 – EPA issues final federal Good Neighbor Plan for the 2015 ozone NAAQS (publication in the Federal Register is still pending).

Attachment B

(2018 SIP)

Infrastructure/110(a) requirements for the 2015 Ozone National Ambient Air Quality Standard

This State Implementation Plan (SIP) revision addresses the infrastructure requirements of sections 110(a)(1) and 110(a)(2) of the Clean Air Act (CAA) in regards to the National Ambient Air Quality Standards (NAAQS) for ozone, promulgated in 2015.

Contents

Introduction

The Minnesota Pollution Control Agency (MPCA) is, via submission of this document, requesting the revision of Minnesota's State Implementation Plan (SIP) under Sections 110(a)(1) and 110(a)(2), as well as Section 128 [as they are related to Section 110(a)(2)(E)(ii)] of the Clean Air Act (CAA). Sections 110(a)(1) and 110(a)(2) of the Act require that states prepare and submit to the U. S. Environmental Protection Agency (EPA) an "infrastructure" SIP (iSIP) within three years of the EPA's issuance of a new National Ambient Air Quality Standard (NAAQS) to demonstrate their continued ability to implement, maintain, and enforce the revised standards. Infrastructure SIP elements include requirements for limiting the interstate transport of air pollution under Section 110(a)(2)(D)(i)(I), commonly called "good neighbor requirements." Section 128 of the CAA mandates that members of boards governing state agencies that implement the Act represent the public interest and disclose any conflict of interest. This iSIP submittal addresses the 2015 ozone NAAQS revision.

The majority of this iSIP revision was written based on EPA's September 12, 2013 guidance document regarding multi-pollutant iSIPs, "Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2)". The 2013 guidance did not address good neighbor elements.

Section 110(a)(2)(D)(i)(I) requires that states ensure that emissions within the state do not contribute significantly to nonattainment in, or interfere with maintenance by, any other state. This requirement means that Minnesota must show that emissions from within its borders are not significantly contributing to air pollution problems or violations in other states. In order to address the good neighbor requirements of this iSIP revision, MPCA referred to EPA's March 27, 2018 memo, "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". Appendices B and C of the 2018 memo, and associated May 18, 2018 updates to modeling activities, provided states with modeled downwind contribution results for receptors that EPA expects will be nonattainment or maintenance areas in 2023. MPCA used the results of EPA's modeling exercise, in addition to modeling conducted by the Lake Michigan Air Directors Consortium (LADCO), to affirm that Minnesota does not contribute to any downwind receptors above the one percent threshold used by EPA to determine significant impact.

The iSIP below discusses each Section under 110(a) and provides information on how Minnesota meets the requirements for each. Based on information set forth in the 2013 guidance, the 2018 memo, previously approved iSIP submittals, and conversations with Region 5 staff, the MPCA believes that this iSIP submittal meets all of the requirements of CAA Sections 110(a)(1) and 110(a)(2).

Section 110(a)(1): A plan which provides for implementation, maintenance, and enforcement

The Minnesota Pollution Control Agency (MPCA) has, in prior submittals, documented its authority and ability to provide for the implementation, maintenance, and enforcement of primary and secondary air quality standards, as well as to adopt enforceable emission limitations and control measures to meet the primary and secondary standard and to update both state rules and the SIP, as necessary.

Various Minnesota statutes, addressed below, authorize the MPCA to adopt air quality standards.

Minn. Statute § 116.07, subd. 2(a) states:

> "The agency shall improve air quality by promoting, in the most practicable way possible, the use of energy sources and waste disposal methods which produce or emit the least air contaminants consistent with the agency's overall goal of reducing all forms of pollution. The agency shall also adopt standards of air quality…, recognizing that due to variable factors, no single standard of purity of air is applicable to all areas of the state…"

Minn. Stat. § 116.07, subd. 4(a), authorizes the agency to "…adopt, amend and rescind rules and standards having the force of law relating to any purpose… for the prevention, abatement, or control of air pollution…"

Under Minn. Stat. 116.07 § subd. 9, the MPCA is granted the authority to enter into or enforce orders, schedules of compliance, and stipulation agreements; to require owners or operators of emission facilities to install and operate monitoring equipment and to conduct tests; and to conduct investigations, issue notices, and order hearings, as deemed necessary, to discharge the MCPA's duties.

Minn. Stat. § 116.072 authorizes the MPCA to issue orders and assess administrative penalties to correct violations of the MPCA's statutes, rules, and permits. The statute also authorizes administrative penalties up to a maximum of $10,000 for all violations identified during an inspection or compliance review.

Minn. Stat. § 115.071, subd. 1 provides that violations of the MPCA's statutes, rules, standards, orders, stipulation agreements, schedules of compliance, and permits may be remedied with criminal prosecution, action to recover civil penalties, injunction, and action to compel performance, other appropriate action, or any combination of the above. Relatedly, Minn. Stat. § 115.071, subd. 3 indicates that civil penalties may be recovered up to a maximum of $10,00 per day of violation, except for violations related to hazardous waste, the maximum for which is $25,000 per day of violation.

Minnesota's SIP-approved air quality rules are established under the above statutory authorities, and broadly cover the criteria pollutants listed, as defined in Minn. R. Ch. 7005.0100: "sulfur dioxide, particulate matter, nitrogen oxides, carbon monoxide, ozone, lead, and any other pollutants for which national ambient air quality standards have been established…" Primary and secondary ambient air quality standards are defined in Minn. R. Ch. 7009.0010 subp. 2 and 3; Minn. R. Ch. 7009.0020 prohibits emissions that cause or contribute to the violation of any ambient air quality standard. The NAAQS are incorporated by reference in Minn. R. Ch. 7009.0090.

We assert that the above statutory and regulatory authorities fulfill the requirements of Section 110(a)(1).

Section 110(a)(2)(A): Emission limits and other control measures

Minn. Stat. Ch. 116 gives the MPCA the authority to develop rules and regulations and also allows the MPCA to implement current rules and apply existing controls and emissions limits to help maintain new standards. Minn. Stat. § 116.07, subd. 4(a) gives the MPCA the authority to "adopt, amend and rescind rules and standards having the force of law relating to any purpose… for the prevention, abatement, or control of air pollution."

Minn. Stat. § 116.07, subd. 4a(a), gives the MPCA authority to "issue, continue in effect or deny permits, under such conditions as it may prescribe for the prevention of pollution, for the emission of air contaminants, or for the installation or operation of any emission facility, air contaminant treatment facility, treatment facility, potential air contaminant storage facility, or storage facility…"

Minnesota does not have any nonattainment or maintenance areas for the 2015 ozone NAAQS; however, there are methods in place to address emissions of nitrogen oxides (NO_x) and volatile organic compounds (VOCs), which are considered by EPA to be the primary precursors to ground-level ozone formation.

Nitrogen oxides (NO_x)

State rules that limit NO_x, as well as nitrogen dioxide (NO_2) emissions, include Minn. R. Ch. 7011.0500 through 7011.0553, which address Indirect Heating Fossil-Fuel-Burning Equipment, and Minn. R. Ch. 7011.1700 through 7011.1730, which address Nitric Acid Plants in Minnesota.

Volatile organic compounds (VOCs)

In order to minimize the formation of ground-level ozone, we limit the emissions of volatile organic compounds (VOCs), which are the primary ozone precursors, through our Part 70 permit program. In addition, Minnesota's state rules incorporate, by reference, the National Emission Standards for Hazardous Air Pollutants (NESHAPs), which, with Part 70 permits, limit VOC emissions. These limits help to protect the 2015 ozone NAAQS.

More information about emissions limits and other control measures can be found in the discussion of Section 110(a)(2)(D)(i)(I) of this document, which reviews Minnesota's interstate transport obligations.

We assert that the above statutory and regulatory authorities fulfill the requirements of Section 110(a)(2)(A).

Section 110(a)(2)(B): Ambient air quality monitoring/data system

Minnesota monitors for ambient ozone levels at 17 locations throughout the state. Minnesota's ambient air quality monitoring network is designed and operated to meet the requirements of 40 CFR Part 58, "Ambient air quality surveillance". Data from the monitors are submitted to the U.S Environmental Protection Agency's (EPA) Air Quality System (AQS) in a timely manner.

The MPCA completes an annual air monitoring network plan for the state, required under 40 CFR § 58.10, which describes the existing air monitoring network, as well as planned and proposed changes. These network plans are available on the MPCA's website, at https://www.pca.state.mn.us/air/air-monitoring-network-plan. The 2019 Annual Air Monitoring Network Plan for Minnesota was posted and available for public comment from May 1 through June 1, 2018, and will be submitted to EPA prior to the July 1, 2018 deadline. The 2019 plan includes a new Appendix D that describes the MPCA's Photochemical Assessment Monitoring Station (PAMS) Network Implementation Plan, which reflects changes in EPA's ambient ozone monitoring requirements that were made as part of the 2015 ozone NAAQS revision. The PAMS Network Implementation Plan has been tentatively approved by EPA per the early review of the 2019 plan.

Minn. Stat. § 116.07, subd. 9(b) gives the MPCA authority "to require the owner or operator of any emission facility, air contaminant treatment facility, potential air contaminant storage facility, or any system or facility related to the storage, collection transportation, processing, or disposal of waste… to install, use, and maintain monitoring equipment or methods…". Information about the industrial monitoring network in Minnesota is available in Appendix B of annual monitoring plan updates.

We assert that the above statutory requirements and associated ambient air quality monitoring practices at MPCA fulfill the requirements of Section 110(a)(2)(B).

Section 110(a)(2)(C): Programs for enforcement and for regulation of PSD and NSR

As described above, Minn. Stat. §§ 116.07, subd. 9, 116.072, and 115.071 give MPCA the authority to enforce any provisions of section 116 and the rules, standards, orders, stipulation agreements, schedules of compliance, and permits adopted or issued thereunder, or under any other law relating to air contamination.

These sections include, but are not limited to, the following authorities:

- Entering into orders
- Schedules of compliance
- Stipulation agreements
- Requiring owners or operators of emissions facilities to install and operate monitoring equipment
- Conduction of investigations

Minn. Stat. § 116.072 authorizes the MPCA to issue orders and assess administrative penalties to correct violations of MPCA's rules, statutes, and permits; Minn. Stat. § 115.071 outlines the remedies that are available to address such violations. Additionally, Minn. R. 7009.0030 and 7009.0040 provide for enforcement measures related to the violation of ambient air quality standards.

Minn. R. Ch. 7007 contains the requirements of the MPCA's permitting program, through which enforceable emission limitations are placed on facilities.

Minnesota previously used delegated authority, under 40 CFR § 52.21, to permit Prevention of Significant Deterioration (PSD) sources through a Federal Implementation Plan (FIP). On October 4, 2016, the MPCA submitted a SIP revision to incorporate new PSD rules, which incorporated federal PSD rules by reference in Minn. R. Ch. 7007.3000. EPA approved the SIP revision, and the new PSD rules, on September 26, 2017 (82 FR 44734); these rules have been incorporated into Minnesota's SIP at 40 CFR § 52.1220.

Although Minnesota does not have any nonattainment or maintenance areas for the 2015 ozone NAAQS, we have an approved nonattainment New Source Review (NSR) program, which was approved by EPA on May 24, 1995 (60 FR 27411). Minn. R. Ch. 7007.4000 through 7007.4030 incorporates, by reference, the NSR requirements specified in 40 CFR Part 51, Appendix S.

To address the pre-construction regulation of the modification and construction of minor stationary sources and minor modifications of major stationary sources, EPA approved Minnesota's minor NSR program on May 24, 1995 (FR notice citation). Since then, MPCA and EPA have relied on these existing provisions to ensure that new and modified sources not captured by the major NSR permitting programs do not interfere with attainment and maintenance of the ozone and other NAAQS.

We assert that the above statutory and regulatory authority fulfill the requirements of Section 110(a)(2)(C).

Section 110(a)(2)(D): Interstate transport provisions ("good neighbor SIPs")

Section 110(a)(2)(D)(i)(I): Prongs 1 (significant contribution to nonattainment) and 2 (interference with maintenance)

This section requires iSIPs to have provisions prohibiting sources from emitting air pollutants in amounts that would contribute significantly to nonattainment or interfere with maintenance in any other state. These interstate transport requirements are often referred to as "good neighbor SIPs". The analyses conducted to support the 2015 ozone good neighbor SIPs show Minnesota does not contribute significantly to air quality problems in any downwind nonattainment or maintenance area. Therefore, no additional controls or emissions limits are required to fulfill Minnesota's good neighbor obligations.

On March 27, 2018, the EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)" (Memo). The Memo built off another, published on October 27, 2017, which provided guidance to air agencies regarding the development of ozone interstate transport components of iSIPs for the 2008 ozone NAAQS.

EPA's Memo includes new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

EPA identifies a four-step framework in the Memo, intended to guide states on how to go about developing good neighbor SIPs:

1. Identify downwind air quality problems;
2. Identify upwind states that contribute enough to those downwind air quality problems to warrant further review and analysis;
3. Identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems; and
4. Adopt permanent and enforceable measures needed to achieve those emissions reductions.

EPA and states have applied this four-tiered approach, shaped by public notice and comment and refined in response to court decisions, to address good neighbor obligations for previous NAAQS revisions.

1. Identify downwind air quality problems

In the Memo, EPA identifies parts of the country projected to have difficulty attaining or maintaining the 2015 ozone NAAQS by the 2023 moderate attainment deadline. To extrapolate ozone design values (DVs) to 2023, EPA used the Comprehensive Air Quality Model with Extensions (CAMx v6.40) to model 2011 and 2023 emissions. EPA used the outputs from the 2011 and 2023 model simulations to create relative response (of air quality to emission changes) factors. EPA applied the relative response factors to project base period 2009-2013 average and maximum ozone DVs to 2023 at monitoring sites across the country. EPA used the projected future year DVs to identify potential 2023 nonattainment and maintenance receptors for the 2015 ozone NAAQS.

In projecting future year DVs, EPA applied its own modeling guidance and an alternative approach suggested during the January 2017 notice of data availability comment period and backed by other relevant analyses. The alternative excludes from the analysis grid cells positioned over water from the 3 x 3 array of model grid cells surrounding monitoring sites in coastal areas. In the upper Midwest, excluding grid cells positioned over water projects Milwaukee Wisconsin (monitoring site 550790085) as a downwind nonattainment receptor. This means EPA expects the Milwaukee site may have difficulty meeting the ozone NAAQS in 2023 without additional control measures applied in culpable States. Including model grid cells over water projects the Milwaukee site as an attainment receptor. This perspective means the Milwaukee site may achieve ozone design values below the NAAQS without additional controls beyond those addressed in the modeled projections.

The Memo outlines possible alternatives when modeling interstate transport. The Lake Michigan Air Directors Consortium (LADCO), a multi-jurisdictional organization comprised of EPA Region V States, provides modeling support for those states, including Minnesota. LADCO has conducted modeling[1] incorporating alternative bullet #4 in the Memo Analytics section to support 2015 ozone good neighbor SIPs.

Specifically, LADCO replicated EPA's 2023EN platform with the exception of substituting Eastern Regional Technical Advisory Committee (ERTAC) [2] EGU estimates for EPAs engineering analysis estimates. The MPCA believes power sector emissions forecasts must address economic factors, preserve system reliability, and include controls or emission reduction measures justified through some legal framework. It is our understanding that the engineering analysis used by EPA to project EGU emissions to 2023 (version EN of the modeling platform) does not comply with these key requirements. The ERTAC estimates incorporate the key requirements. Table 1 outlines the primary differences between the EPA "engineering analysis" and ERTAC handling of the key requirements. The incorporation of ERTAC in the model simulation produces some new, and changes the status of some, nonattainment or maintenance receptors downwind of Minnesota. Tables 2 and 3 (columns 3 through 6) show the differences.

Table 1. Primary differences between EPA's engineering analysis and LADCO's ERTAC analysis.

Key requirement	EPA engineering analysis	ERTAC
Economic factors	Minimal Economic factors considered. No growth from 2016 to 2023.	Complex growth algorithm based on Annual Energy Outlook (AEO) projections for annual growth and North American Electric Reliability Corporation (NERC) for peak day growth. Growth applied by fuel type and region based on AEO splits.
Preservation of system reliability	No implicit check for reliability.	Complex set of algorithms check system wide capacity against the demand plus safety margins to verify if there is a lack of generation in a region.
Controls or emission reduction measures justified through a legal framework	Applied emission reductions by optimizing existing controls that in 2016 were not optimized without justification the controls will be optimized.	Only applied emission reduction estimates with justification.

2. Upwind states' contributions to downwind air quality problems

EPA has previously determined that a state contribution to downwind air quality problems below one percent of the applicable NAAQS is insignificant. This screening method was used in previous good neighbor SIP approvals, including (most notably) the Cross-State Air Pollution Rule (CSAPR), and the CSAPR update for the 2008 ozone NAAQS and 2012 NAAQS for particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$). The one percent screening method was developed through several previous federal notice and comment rulemakings. One percent of the 2015 ozone NAAQS (70 ppb) is 0.70 ppb. Therefore, any state that contributes less than 0.70 ppb to a projected nonattainment or maintenance area in another state is not culpable for those air quality problems.

EPA and LADCO implemented the Anthropogenic Precursor Culpability Analysis (APCA) technique in CAMx to identify upwind states culpable for downwind ozone air quality problems. The method accounts for human-made nitrogen oxides (NO_x) and volatile organic carbon (VOC) emissions from all sources in each upwind state affecting projected 2023 ozone concentrations at each downwind air quality monitoring site designated a nonattainment or maintenance receptor. EPA and LADCO conducted the culpability analysis for the period May 1 through September 30, using the 2023 future emission estimates and 2011 meteorology. Refer to pages 5 and 6 of the Memo for more information regarding EPA's culpability analysis.

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[1] See Attachment 1, "Interstate Transport Modeling for the 2015 Ozone National Ambient Air Quality Standard: Technical Support Document". The TSD includes text about excluding data from the design value calculation based on model performance. The data in this iSIP, Tables 2 and 3, do not reflect this feature.
[2] See Attachment 2, "Documentation of ERTAC EGU CONUS Versions 2.7 Reference and CSAPR Update Compliant Scenario".

Both analyses conclude Minnesota is not culpable for ozone nonattainment, or interference with maintenance, in any downwind states. As shown in Table 2, EPA's analysis indicates Minnesota contributes most to Milwaukee, Wisconsin monitor site 550790085. At a concentration of 0.40 ppb, this contribution is roughly equal to 0.57% of the 2015 ozone NAAQS (70 ppb). LADCO's analysis corroborates EPA's results, showing a concentration of 0.45 ppb, roughly equal to 0.64% of the NAAQS.

While there are some differences in the list of receptors identified as nonattainment or maintenance receptors between the EPA and LADCO modeling exercises, there are no significant differences in Minnesota's contribution to any of the receptors identified by either EPA or LADCO. Although Minnesota 2023 emission estimates with ERTAC are lower than the EPA engineering analysis estimates, Minnesota's downwind culpability remains the same – negligible – as shown in Tables 2 and 3.

Table 2. Minnesota's projected 2023 ozone contributions, from human-made NO_x and VOC emissions, to states with nonattainment or maintenance receptors, based on the "no water" alternative. Source of EPA model data: "March 2018 Memo and Supplemental Information Regarding Interstate Transport SIPs for the 2015 Ozone NAAQS", https://www.epa.gov/airmarkets/march-2018-memo-and-supplemental-information-regarding-interstate-transport-sips-2015; these data include the May 18, 2018 updates. ERTAC-substituted model and data sourced from LADCO – see Attachments 1 and 2. Values in gray did not exceed the 70 ppb modeling threshold used to identify projected 2023 nonattainment or maintenance areas.

AQS Site ID	Monitor Location	EPA 2023en Average (ppb)	EPA 2023en Maximum (ppb)	LADCO 2023en Average (ppb)	LADCO 2023en Maximum (ppb)	EPA Contribution from Minnesota (ppb)	Percent of 2015 ozone NAAQS	LADCO Contribution from Minnesota (ppb)	Percent of 2015 ozone NAAQS
550790085	Milwaukee, WI	71.2	73.0	68.0	71.2	0.40	0.57	0.45	0.64
180910005	LaPorte, IN	67.2	70.4	65.6	68.6	0.36	0.51	0.34	0.49
480391004	Brazoria, TX	74.0	74.9	73.6	74.4	0.34	0.49	0.33	0.47
170317002	Cook, IL	66.8	70.3	64.7	68.1	0.33	0.47	0.32	0.46
211110027	Jefferson, KY	70.1	70.1	61.7	64.1	0.32	0.46	0.22	0.31
261630019	Wayne, MI	69.0	71.0	67.7	69.7	0.31	0.44	0.30	0.43
551170006	Sheboygan, WI	72.8	75.1	70.9	73.2	0.28	0.40	0.27	0.39
550890008	Ozaukee, WI	67.2	70.5	65.7	68.9	0.26	0.37	0.24	0.34
482010026	Harris, TX	67.6	70.0	66.8	69.1	0.24	0.34	0.27	0.39
482011034	Harris, TX	70.8	71.6	70.2	71.0	0.23	0.33	0.30	0.43
482450101	Jefferson, TX	68.2	70.0	67.8	69.5	0.23	0.33	0.23	0.33
482011039	Harris, TX	71.8	73.5	71.0	72.7	0.20	0.29	0.26	0.37
90099002	New Haven, CT	69.9	72.6	66.8	69.4	0.19	0.27	0.16	0.23
340150002	Gloucester, NJ	68.2	70.4	65.9	68.0	0.18	0.26	0.17	0.24
361030002	Suffolk, NY	74.0	75.5	70.8	72.2	0.18	0.26	0.16	0.23
90010017	Fairfield, CT	68.9	71.2	65.8	68.0	0.17	0.24	0.17	0.24
360810124	Queens, NY	70.2	72.0	67.1	68.8	0.17	0.24	0.16	0.23
90013007	Fairfield, CT	71.0	75.0	68.1	71.9	0.15	0.21	0.15	0.21
484392003	Tarrant, TX	72.5	74.8	72.1	74.3	0.15	0.21	0.15	0.21
90019003	Fairfield, CT	73.0	75.9	70.1	72.9	0.14	0.20	0.11	0.16
484393009	Tarrant, TX	70.6	70.6	70.3	70.3	0.14	0.20	0.14	0.20
240251001	Harford, MD	70.9	73.3	69.2	71.5	0.13	0.19	0.12	0.17
484393011	Tarrant, TX	68.0	70.0	67.6	69.5	0.13	0.19	0.14	0.20
360850067*	Richmond, NY	67.1	68.5	64.5	65.8	0.12	0.17	0.12	0.17
260050003	Allegan, MI	69.0	71.7	67.4	70.1	0.11	0.16	0.11	0.16
481210034	Denton, TX	69.7	72.0	69.4	71.7	0.11	0.16	0.11	0.16
90110124	New London, CT	67.3	70.4	63.9	66.9	0.09	0.13	0.09	0.13
220330003	East Baton Rouge, LA	67.8	70.6	66.6	69.4	0.07	0.10	0.07	0.10
421010024	Philadelphia, PA	67.3	70.3	65.3	68.2	0.07	0.10	0.09	0.13
480290052	Bexar, TX	68.4	70.4	68.3	70.3	0.06	0.09	0.06	0.09
482010024	Harris, TX	70.4	72.8	69.7	72.1	0.06	0.09	0.06	0.09

*The Richmond, NY site was first included by EPA in the March 27 memo, as it was shown to be a nonattainment receptor in the "water" modeling approach. See Table 3 for projected DV information.

Table 3 shows the list of receptors EPA identified in Appendix B of the Memo using the "water" (non-alternative) cell approach. EPA did not identify state-by-state contributions for this approach, but we include those receptors here for comparison to LADCO's modeling.

Table 3. Minnesota's projected 2023 ozone contributions, from human-made NO_X and VOC emissions, to states with nonattainment or maintenance receptors, based on the "water" alternative. Source of EPA model data: Memo, Attachment B, "Projected ozone design values at potential nonattainment and maintenance receptors based on EPA's updated 2023 transport modeling", p. B-3. Updates to these values were not provided with the other May 18, 2018 updates under the "no water" alternative. ERTAC-substituted model and data sourced from LADCO – see Attachments 1 and 2. Values in gray did not exceed the 70 ppb modeling threshold used to identify projected 2023 nonattainment or maintenance areas.

AQS Site ID	Monitor Location	EPA 2023en Average (ppb)	EPA 2023en Maximum (ppb)	LADCO 2023en Average (ppb)	LADCO 2023en Maximum (ppb)	EPA Contribution from Minnesota (ppb)*	Percent of 2015 ozone NAAQS*	LADCO Contribution from Minnesota (ppb)	Percent of 2015 ozone NAAQS
550790085**	Milwaukee, WI	65.4	67.0	62.1	65.1	---	---	0.41	0.59
480391004	Brazoria, TX	74.0	74.9	73.6	74.4	---	---	0.33	0.47
261630019	Wayne, MI	69.0	71.0	67.7	69.7	---	---	0.30	0.43
482011034	Harris, TX	70.8	71.6	70.2	71.0	---	---	0.30	0.43
551170006	Sheboygan, WI	70.8	73.1	69.3	71.5	---	---	0.27	0.39
482011039	Harris, TX	71.8	73.6	71.0	72.7	---	---	0.26	0.37
90099002	New Haven, CT	71.2	73.9	67.9	70.5	---	---	0.17	0.24
90010017	Fairfield, CT	69.8	72.1	67.2	69.4	---	---	0.17	0.24
361030002	Suffolk, NY	72.5	74.0	69.8	71.3	---	---	0.16	0.23
360810124	Queens, NY	70.1	71.9	67.5	69.2	---	---	0.16	0.23
484392003	Tarrant, TX	72.5	74.8	72.1	74.3	---	---	0.15	0.21
90013007	Fairfield, CT	71.2	75.2	67.8	71.6	---	---	0.15	0.21
484393009	Tarrant, TX	70.6	70.6	70.3	70.3	---	---	0.14	0.20
360850067	Richmond, NY	71.9	73.4	69.1	70.6	---	---	0.13	0.19
240251001	Harford, MD	71.4	73.8	69.4	71.8	---	---	0.12	0.17
90019003	Fairfield, CT	72.7	75.6	69.6	72.4	---	---	0.11	0.16
260050003	Allegan, MI	69.0	71.8	67.1	69.8	---	---	0.11	0.16
481210034	Denton, TX	69.7	72.0	69.4	71.7	---	---	0.11	0.16
480290052	Bexar, TX	---	---	68.3	70.3	---	---	0.06	0.09
482010024	Harris, TX	70.4	72.8	69.7	72.1	---	---	0.06	0.09

*Although EPA modeled projected ozone values and identified potential nonattainment and maintenance receptors for both the "water" and "no water" alternatives, EPA did not provide state-by-state contributions to the 2023 8-hour ozone DVs for the "water" scenario in Appendix C or the excel files accompanying the Memo.
**Although the Milwaukee, WI site was not identified as a potential nonattainment or maintenance receptor by either EPA or LADCO under the "water" alternative, we've included it here to demonstrate that it is still the receptor for which Minnesota's contribution is highest.

LADCO's analyses have, in addition to EPA's, concluded that Minnesota is not culpable for ozone nonattainment, or interference with maintenance, in any downwind states.

3. Identify emissions reductions necessary (if any)

Neither the EPA or the LADCO analyses identified any potential nonattainment or maintenance receptors significantly impacted by ozone transport from Minnesota in 2023. For previous good neighbor SIP submittals, the EPA has relied on a one percent threshold to determine significant downwind contributions of regional pollutants. As stated previously and shown in Tables 1 and 2, the highest contribution from Minnesota modeled by EPA and LADCO was at Site 550790085 in Milwaukee, WI; all models showed our contributions to be significantly below the one percent (0.70 ppb) threshold for the 2015 ozone NAAQS. Therefore, Minnesota does not have a responsibility to identify or implement any further controls or emissions limits to reduce downwind ozone contribution.

The following information provides strengthening evidence to the above modeling analysis.

Ambient ozone concentrations in Minnesota

Minnesota has never been in nonattainment for any promulgated ozone NAAQS, and ambient ozone concentrations in Minnesota have consistently been near or below the NAAQS. Figure 1 shows ozone concentrations as a percent of the NAAQS for each given year. Figure 1 shows data starting in 1997, which was the year that the form of the standard changed to represent the "annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years". This continues to be the current form, although the level of the standard has been lowered twice since that first change.

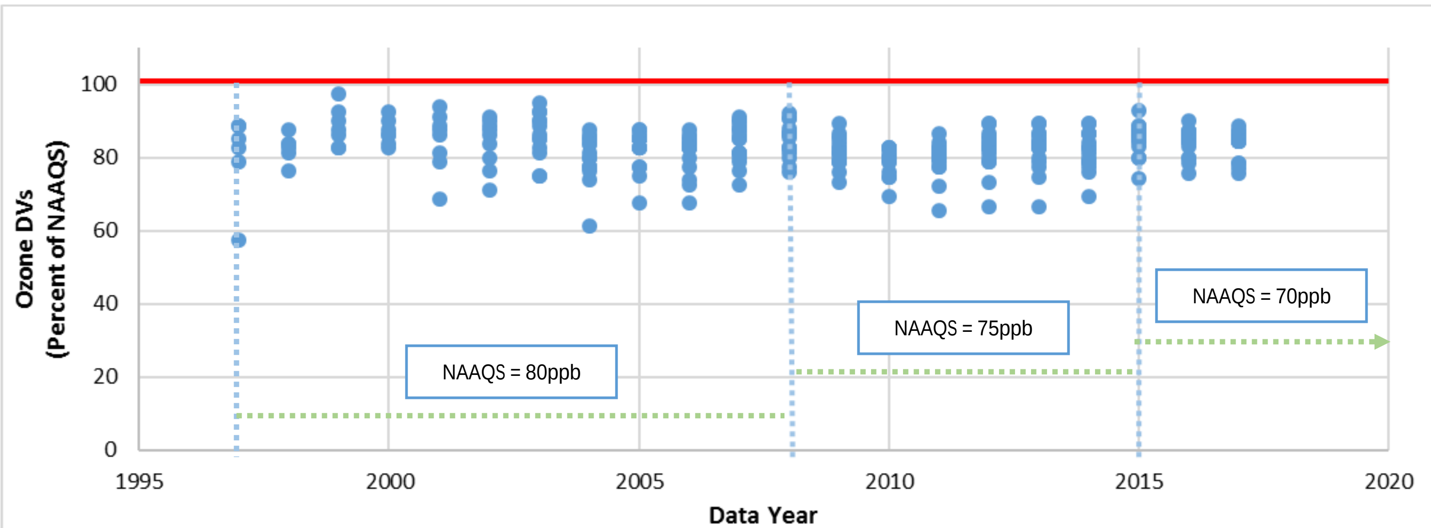

Figure 1. 8-hour (annual fourth-highest daily maximum 8-hr concentration, averaged over 3 years) ozone DVs from Minnesota ambient ozone monitors, shown as percentage of NAAQS, from 1997-2017. Although monitors throughout the state show a range of ambient concentration values, Minnesota has never had an exceedance of any promulgated ozone NAAQS.

As discussed above in Section 110(a)(2)(B), there are currently 17 ozone monitors located throughout the state. Monitoring data from 2015-2017, as shown in Figure 2, indicate that the highest ozone concentration is at Site 27-003-1002, the Anoka Airport in Blaine. At 62ppb, the 2015-2017 DV was at approximately 89 percent of the 70ppb NAAQS.

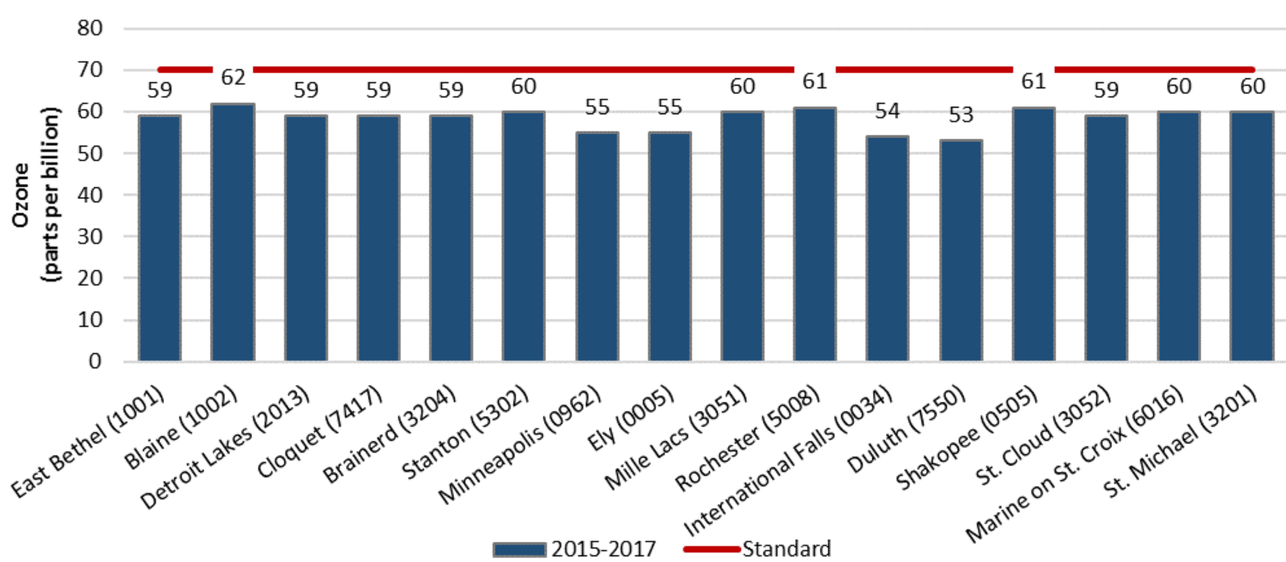

Figure 2. 8-hour average ozone concentrations compared to the 2015 ozone NAAQS, 2015-2017

Minnesota's ambient ozone concentrations are steadily decreasing; it would be reasonable to assume that Minnesota is, therefore, contributing less to ozone concentrations in other states.

Nitrogen oxides (NO_x) and volatile organic compound (VOC) emissions in Minnesota

When conducting modeling with the CAMx APCA platform, EPA identified anthropogenic (human-made) NO_x and VOCs as the primary precursors to ground-level ozone formation. Thus, we will focus our discussion of emissions reductions in Minnesota on NO_x and VOC emissions data.

NO_x emissions have been steadily declining in Minnesota over the past several years. Figure 3 demonstrates the steady decline of emissions from point (permitted), non-point (neighborhood), on-road mobile, and non-road equipment. The largest reductions in emissions have come as a result of emissions limits and reductions at point sources, particularly electric generating utilities (EGUs). Point source emissions reporting is required annually.

Every three years MPCA collects expanded emissions inventories from non-point, on-road, and mobile sources, and works with EPA to identify emissions categories and to verify state-collected data, if necessary. NO_x emissions from these traditionally non-permitted sources have also been declining, though less rapidly than for point sources.

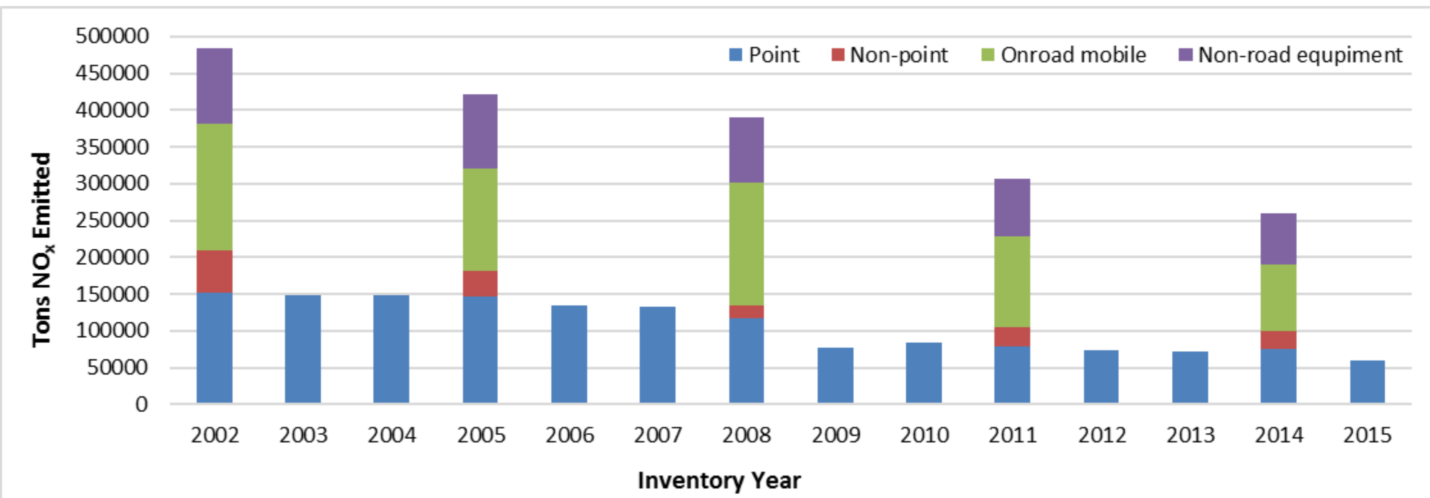

Figure 3. Reported (actual) NO_x emissions for the state of Minnesota, 2002-2015. Inventory data for 2014 are preliminary.

As with NO_x emissions, VOC emissions have been steadily declining in Minnesota over the past several years. Figure 4 shows emissions from point (permitted), non-point (neighborhood), on-road mobile, and non-road equipment.

Again, as with NO_x, MPCA collects expanded emissions inventories from non-point, on-road, and mobile sources every three years. Although some VOC emission reductions have resulted as a co-benefit of emissions limits on point sources, the majority of VOC emission reductions in recent years has come from lower on-road mobile source emissions, primarily through Minnesotans' use of cleaner, more fuel efficient vehicles.

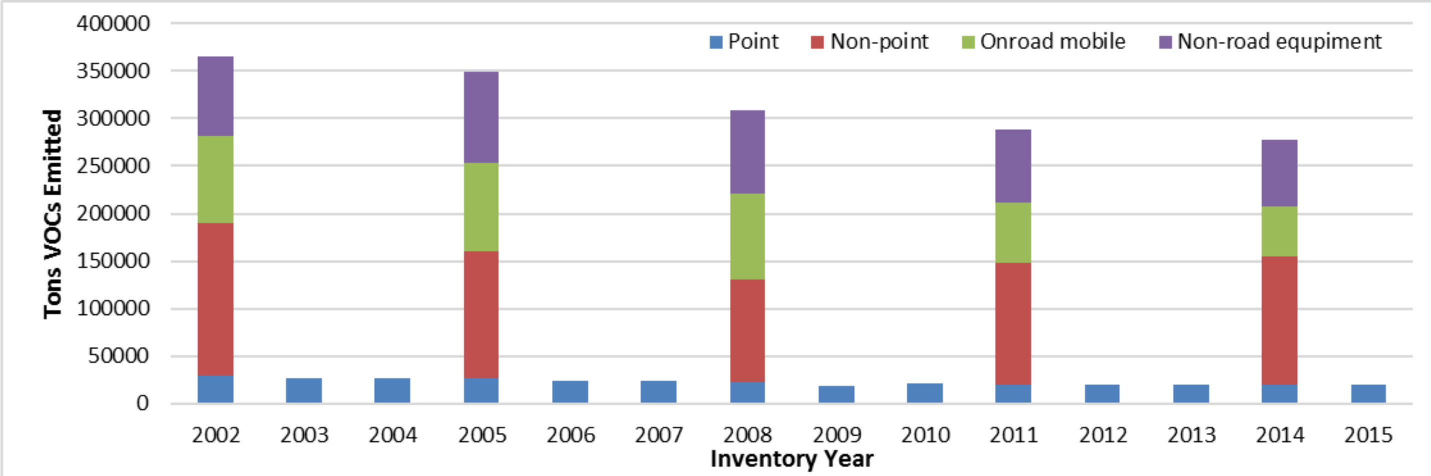

Figure 4. Reported (actual) VOC emissions for the state of Minnesota, 2002-2015. Inventory data for 2014 are preliminary.

4. Adopt permanent and enforceable measures needed to achieve reductions identified in item 3.

Since NO_x and VOC emissions in Minnesota continue to decrease, ozone formation is also declining; ozone is not directly emitted by any sources. This, in combination with the fact that Minnesota is not expected to contribute to any nonattainment or maintenance issues downwind by the year 2023, makes it such that no additional permanent or enforceable measures, beyond those already implemented in the state, are needed at this time.

Current measures that limit emissions of these pollutants and therefore help maintain Minnesota's insignificant contribution to downwind air quality concerns are discussed below.

Multi-pollutant limits

Minnesota has several methods of limiting emissions from facilities in the state. The primary way in which emissions of NO_x and VOCs are limited in Minnesota is through emissions limits described in Part 70 permits.

Minnesota is subject to CSAPR's annual NO_x programs, which were developed to address the 1997 and 2006 $PM_{2.5}$ NAAQS. The CSAPR regulations have resulted in a reduction of NO_x emissions from power plants subject to the rule (see Figure 3, above). In addition, many of Minnesota's coal-fired boilers have been converting to natural and/or fuel gas over the past several years, in response to state regulations to reduce mercury emissions (Mercury Emissions Reduction Act of 2006), as well as more recent Mercury and Air Toxics Standards (MATS). Although intended to reduce mercury emissions, these regulations have also resulted in reductions in co-pollutants, like NO_x and SO_2.

Pollutant-specific limits

Minnesota has, in addition to multi-pollutant limits, pollutant-specific methods of limiting emissions. Most of our pollutant-specific limits are for SO_2 and particulate matter, as those are the two pollutants for which we have had nonattainment (and subsequently, maintenance) areas.

NO_x

State rules that limit NO_x and NO_2 emissions include:

- Minn. R. Ch. 7011.0500 to 7011.0553, for Indirect Heating Fossil Fuel Burning Equipment

- Minn. R. Ch. 7011.1700 to 7011.1705, for Nitric Acid Plants

Minnesota has issued an Administrative Order (AO) to Xcel Energy – Northern States Power Company, Sherburne County Generating Station, as part of Minnesota's Regional Haze SIP. The AO includes NO_x emissions limits.

VOCs

The majority of VOC emissions in Minnesota come from nonpoint (neighborhood) and small point sources. Minnesota's state rules incorporate, by reference, the National Emission Standards for Hazardous Air Pollutants (NESHAPs), which limit VOC emissions. The primary method by which we limit VOC emissions is through the issuance of Part 70 permits and Title I emissions limits in permits, which can help small sources avoid classification as major sources when unnecessary.

The MPCA has statewide partnerships with non-profit organizations, the University of Minnesota, state contractors, and local governments to promote the voluntary reduction of VOCs through education programs and the administration of grants to small businesses, particularly auto body and coating shops.

Summary: Prongs 1 and 2

It can be reasonably concluded from the above analyses that Minnesota does not, and will not by 2023, significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS at any of EPA's identified receptors. Minnesota has not historically contributed significantly to any of the monitors projected to have nonattainment or maintenance issues in 2023. Our emissions of ozone precursors, NO_x and VOCs, are on a downward trend, and our emissions sources currently have limits and controls that will continue to reduce ozone concentrations via a reduction in precursors.

EPA's own modeling showed a downwind contribution of less than one percent at all examined receptors, which has historically been accepted as a demonstration that ozone transport will not affect any nonattainment or maintenance receptors, as identified, for the year 2023.

It follows that the limits and controls that Minnesota already has in place across the state are sufficient to make it reasonably certain that Minnesota will not significantly contribute to nonattainment or interfere with maintenance in any other state. We assert that no further controls or emissions limits are required to fulfill our responsibilities under the interstate transport provisions for the 2015 ozone NAAQS under prongs 1 and 2 of Section 110(a)(2)(D)(i)(I).

Section 110(a)(2)(D)(i)(II): Prongs 3 (interference with PSD) and 4 (interference with visibility protection)

This section requires iSIPs to include provisions prohibiting any source or other type of emissions activity in one state from interfering with measures required to prevent significant deterioration of air quality or the protection of visibility in another state.

As mentioned above, Minnesota has recently had its PSD program (at Minn. R. Ch. 7007.3000) approved into the SIP at 40 CFR § 52.1220, and so continues to operate a federally-approved nonattainment NSR (NNSR) permitting program. Thus, all new major sources and major modifications are subject to a comprehensive, EPA-approved permitting program that applies to all NSR pollutants. These programs require the consideration of emission impacts on the air quality of other states. Minn. R. Ch. 7007.0900 provides for the review of Part 70 permits by affected states.

Minnesota does not have any nonattainment areas for the 2015 ozone NAAQS; however, NNSR rules have been promulgated, and are contained in Minn. R. Ch. 7007.4000-7007.4030. These rules ensure that, if there ever is an instance where an area in the state becomes nonattainment, the sources located in those areas would not interfere with neighboring states' PSD programs.

EPA approved significant portions of Minnesota's Regional Haze (RH) SIP on June 12, 2012 (77 FR 34801); however, due to the disapproval of various components, Minnesota is currently subject to a Federal Implementation Plan (FIP) for unapproved sources. Sources that are within Minnesota's jurisdiction – that that were approved in the RH SIP – are not interfering with neighboring states' abilities to protect visibility. Visibility in the two Class I areas within the state of Minnesota continues to improve, as well. Interim visibility goal targets, which show 2018 as a target year, are being met in both locations.

Based on our discussed PSD and RH program components, we assert that Minnesota meets the requirements of prongs 3 and 4 of Secion 110(a)(2)(D)(i)(II).

Section 110(a)(2)(D)(ii): Interstate pollution abatement and international air pollution

Minnesota administers a federally-approved PSD program through Minn. R. Ch. 7007.3000, which incorporates, by reference, 40 CFR § 52.21. Subsequently, new or modified sources are required to notify neighboring states of potential negative air quality impacts. Our previous iSIP submittal for this section was disapproved due to the underlying issues with the PSD program. Now that Minnesota's PSD program has been approved, we assert that Minn. R. Ch. 7007.3000 fulfills the requirements of Section 110(a)(2)(D)(ii), as well as interstate pollution abatement requirements under Section 126(a). Minnesota has no other obligations under Section 126, nor under the international pollution abatement components of Section 115.

We assert that the above regulatory authority fulfills the requirements of Section 110(a)(2)(D)(i)(II).

Section 110(a)(2)(E): Adequate resources and authority, conflict of interest, and oversight of local governments and regional agencies

Per Minn. St. § 116.07, the MPCA is granted the authority and responsibility for developing, implementing, and enforcing rules that allow Minnesota to comply with the Clean Air Act (CAA), including maintenance of the SIP. MPCA's Performance Partnership Agreement (PPG) with EPA provides MPCA the assurances to the availability of resources needed to carry out certain air programs.

MPCA's authority to enforce the NAAQS has been demonstrated previously in this document.

Minnesota's satisfaction of section 110(a)(2)(E)(ii), as it relates to state board requirements of Section 128, is discussed near the end of this document. The rules submitted in this iSIP in order to meet the requirements of Section 128 also satisfy any applicable requirements related to section 110(a)(2)(E)(ii) for the 2015 ozone NAAQS. To the extent that the state board requirements are non-NAAQS specific, we request that EPA also approve these rules as satisfying the applicable Section 110(a)(2)(E)(ii) requirements for any NAAQS for which final action has not been taken.

We assert that the above statutory authority, in tandem with that presented below for Section 128, fulfills the requirements of Section 110(a)(2)(E).

Section 110(a)(2)(F): Stationary source monitoring and reporting

Minn. Stat. § 116.07, subd. 9(b) gives the MPCA authority "to require the owner or operator of any emission facility, air contaminant treatment facility, potential air contaminant storage facility, or any system or facility related to the storage, collection transportation, processing, or disposal of waste... to install, use, and maintain monitoring equipment or methods...".

Minn. R. Ch. 7007.0800, subp. 4 describes the minimum monitoring requirements included in each permit for major stationary sources. Minn. R. Ch. 7011, which includes standards for stationary sources, also lists monitoring requirements for each applicable source category.

Minn. R. Ch. 7017 contains Minnesota's air monitoring and testing requirements, including for continuous monitoring.

Minn. R. Ch. 7019 contains emissions reporting requirements for applicable facilities, which must submit annual emissions inventories to MPCA. The inventory reports must contain information on all criteria pollutants for which a NAAQS has been promulgated. The MPCA also collects emissions inventory for air toxics, including VOCs, on a triennial basis.

The majority of applicable rules in Chs. 7007, 7011, 7017, and 7019 have been previously approved by EPA and subsequently incorporated into Minnesota's SIP at 40 CFR § 52.1220.

We assert that the above statutory and regulatory authorities fulfill the requirements of Section 110(a)(2)(F).

Section 110(a)(2)(G): Emergency episodes

Although historic ambient monitoring data does not indicate a need for specific contingency measures for ozone, Minn. Stat. § 116.11 was promulgated to allow the MPCA to halt or abate specific sources of pollution during an emergency.

Minn. Stat. § 116.11 reads:

> "If there is imminent and substantial danger to the health and welfare of the people of the state, or of any of them, as a result of the pollution of air, land, or water, the agency may by emergency order direct the immediate discontinuance or abatement of the pollution without notice and without a hearing or at the request of the agency, the attorney general may bring an action in the name of the state in the appropriate district court for a temporary restraining order to immediately abate or prevent the pollution. The agency order or temporary restraining order shall remain effective until notice, hearing, and determination pursuant to other provisions of law, or, in the interim, as otherwise ordered. A final order of the agency in these cases shall be appealable in accordance with chapter 14."

Minn. R. Ch. 7000.5000 elaborates on specific actions to be taken to notify and communicate about any emergency declared by the commissioner. Further instruction and requirements for owners and operators of any facility or stationary source during air pollution episodes are provided in Minn. R. Ch. 7009.1000 through 7009.1110.

We assert that the above statutory and regulatory authorities fulfill the requirements of Section 110(a)(2)(G).

Section 110(a)(2)(H): Future SIP revisions

The MPCA has submitted many updates to the SIP at 40 CFR § 52.1220 in the last several years, in addition to iSIPs when required by the Clean Air Act. We intend to continue to submit updates, as needed, in order to ensure changes at existing facilities will not jeopardize the NAAQS, to comply with new or revised NAAQS, or as requested by EPA (e.g., during a "SIP call"). Language confirming the MPCA's ability to adopt or rescind rules and standards related to air pollution can be found in Minn. Stat. § 116.07, subd. 4.

MPCA's authority to issue permits to regulate air pollution can be found in Minn. Stat. § 116.07, subd. 4a.

We assert that the above statutory authority fulfills the requirements of Section 110(a)(2)(H).

Section 110(a)(2)(I): Plan revisions for nonattainment areas

Per EPA's interpretation of the CAA and direction provided in the 2013 iSIP guidance document[3], states are not required to address this Section, as SIP submissions for specific nonattainment areas, as required under the CAA Title I, part D, are subject to a different submission schedule. The MPCA, is not, therefore, addressing Section 110(a)(2)(I) as a part of this iSIP.

Section 110(a)(2)(J): Consultation with government officials, public notification, and PSD and visibility protection

Consultation with government officials

Historically, MPCA actively participated in the Central Regional Air Planning Association, as well as the Central States Air Resource Agencies. MPCA is now a full-time member of the Lake Michigan Air Director's Consortium (LADCO), and has demonstrated that it frequently consults and discusses air quality issues with pertinent Tribes. In addition to LADCO, MPCA is an active participant in the National Association of Clean Air Agencies (NACAA), which has a member total of 185 air agencies, including representatives from all EPA regional offices and headquarters, across the United States.

Public notification

Minnesota dedicates portions of the MPCA website to enhancing public awareness of measures that can be taken to prevent exceedance of all NAAQS generally. Information for non-point (neighborhood), vehicle, and traditionally permitted sources can be found on MPCA's website, at https://www.pca.state.mn.us/air/sources-air-pollution. Information regarding the health impacts of air pollution, especially particulate matter and ozone, can be found at https://www.pca.state.mn.us/air/air-quality-and-health; current air quality and air quality forecasting for the entire state of Minnesota, new in 2017, is also available, at https://www.pca.state.mn.us/air/current-air-quality. MPCA staff developed a free mobile app that provides the same forecasting information as the website, but in a more mobile-friendly format; the app, Minnesota Air, is available for both iOS (Apple) and Android platforms, and can be download through the iOS App Store or Android's Google Play.

Minnesota's procedural rules, applicable across all MPCA media programs, are established in Minn. R. Ch. 7000; these rules include general guidelines, as well as information about contested case hearings (7000.1750 through 7000.2200), emergency and variance procedures (7000.5000 and 7000.7000), and ethical conduct and standards (7000.9000 and 7000.9100).

[3] Memorandum dated September 13, 2013, "Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2)".

Minn. R. Ch. 7007.0850 lists public notice and comment procedures for the issuance of air quality permits. The public may petition for meetings and hearings, including for a contested case hearing, as it relates to any air permit (with reference back to Minn. R. Ch. 7000.1800). In addition to public notice of each air permit being issued by the MPCA, each SIP revision is put on notice, and the public is provided the opportunity to comment and/or request public hearings regarding proposed SIP revisions. This includes iSIPs, any SIP updates at 40 CFR § 52.1220, and site-specific SIP conditions incorporated into air permits at individual facilities (under title I and title 5).

Minn. R. Ch. 7007.0900 also provides for the review of part 70 permits by affected states. Specifically, "[t]he agency shall give notice of each draft part 70 permit, or major amendment to a part 70 permit, to any affected state on or before the time that the agency provides this notice to the public as required by part 7007.0850."

PSD and visibility protection

As described previously in greater detail, Minnesota's PSD program was recently approved by EPA and has been incorporated into the SIP at 40 CFR § 52.1220.

MPCA works with Federal Land Managers on a regular basis to discuss issues impacting Minnesota's Class I areas, including the U.S. Forest Service and the National Park Service.

MPCA is not, however, addressing visibility protection any further in this portion of the iSIP, per EPA's 2013 SIP guidance. The guidance states, on p. 55, that "[t]he EPA believes that there are no new visibility protection requirements under part C [of CAA title I, which is implemented through 40 CFR part 51 subp. P] as a result of a revised NAAQS. Therefore, there are no newly applicable visibility protection obligations pursuant to Element J after the promulgation of a new or revised NAAQS. Air agencies do not need to address the visibility subelement of Element J in an infrastructure SIP submission."

Summary

We assert that the above regulatory authority fulfills the requirements of Section 110(a)(2)(J).

Section 110(a)(2)(K): Air quality modeling and submission of modeling data

MPCA reviews the potential impact of major and some minor new sources.

Under Minn. R. Ch. 7007.0500, MPCA may require applicable major sources to perform modeling in order to demonstrate that emissions do not cause or contribute to a violation of any NAAQS. Minn. R. Ch. 7007.0500, subp. 1E, states that MPCA may notify an applicant that they are required to demonstrate that their emissions do not cause a violation of ambient air quality standards. Such information is mandatory for applicants subject to PSD requirements (Minn. R. Ch. 7007.3000) and/or NNSR requirements (Minn. R. Ch. 7007.4000 through 7007.4030).

The MPCA routinely requests and requires emissions information from air permit applicants. MPCA also maintains expert staff that conduct permit-related (and other) modeling, to support facilities and ensure modeling accuracy, as needed. More information on the MCPA's air modeling program can be found at https://www.pca.state.mn.us/air/air-quality-modeling.

Section 110(a)(2)(L): Permitting fees

The MPCA implements and operates Minnesota's Title V permit program, which EPA approved in full on December 4, 2001 (66 FR 62967). Included in our permit program are Minn. R. Ch. 7002.0005 through 7002.0085, Air Emission Permit Fees, which contain the provisions, requirements, and procedural structures associated with the costs for reviewing, approving, implementing, and enforcing various types of air permits.

We assert that the above regulatory authority, in addition to the approved Title V permit program, fulfills the requirements of Section 110(a)(2)(L).

Section 110(a)(2)(M): Consultation and participation by affected local entities

The MPCA develops, implements, and enforces Minnesota's air quality program and, in doing so, regularly consults with local political subdivisions affected by the SIP.

Under Minn. Stat. § 116.05, other departments and agencies are directed to cooperate with the MPCA, and the MPCA is granted the authority to work with those agencies.

Specifically, Minn. Stat. § 116.05, subd. 1, states that MPCA is "…authorized to cooperate and to enter into necessary agreements with other departments and agencies of the state, with municipalities, with other states, with the federal government and its agencies and instrumentalities in the public interest and in order to control pollution…"

The Minnesota Administrative Procedures Act (Minn. Stat. Ch. 14) provides general notice and comment procedures that govern rulemaking for all state agencies, which the MPCA follows during SIP development. For example, all SIP revisions are put on public notice in the state register; in doing so, the public is provided the opportunity to request a public meeting or comment on the SIP document. If a public meeting is requested, the MPCA will hold one.

We assert that the above statutory and regulatory authorities fulfill the requirements of Section 110(a)(2)(M).

Section 128: State board requirements [as related to Section 110(a)(2)(E)(ii)]

Section 128(a) of the CAA has two requirements:

> (1) that any board or body which approves permits or enforcement orders under this chapter shall have a majority of members who represent the public interest and do not derive any significant portion of their income from persons subject to permits and enforcement orders under this chapter, and
> (2) that any potential conflicts of interest by members of such board or body or the head of an executive agency with similar powers be adequately disclosed. Section 110(a)(2)(E)(ii) requires that states demonstrate compliance with section 128 as part of their Infrastructure SIP (see above).

Per statutory changes from the 2015 legislative session, the state of Minnesota no longer has any board or body which approves permits or enforcement orders in relation to the CAA. We do, however, have rules and statutes which address any potential conflicts of interest by the head of executive agencies that are applicable under the CAA.

The MPCA submitted the following statutes and rules to EPA on May 26, 2016, in addition to the Section 110(a)(2)(D) provisions for the 2008 ozone NAAQS. Per 82 FR 50807, published November 2, 2017, Minnesota's state board requirements – including the elements below – were approved for our previous multi-pollutant iSIP (effective December 4, 2017).

Section 128(a)(1)

Minnesota has no board or body which approves permits or enforcement orders in relation to the CAA. Instead, Minn. Stat. § 116.02, subd. 5, and Minn. Stat. § 116.03, subd. 1 provide the MPCA's Commissioner with the authority, powers, and duties to make decisions on behalf of the agency.

Section 128(a)(2)

Minnesota's statutes and rules require disclosure of any potential conflict of interest by public officials. Under Minn. Stat. Ch. 10A, matters of disclosure and public interest are governed by the Minnesota Campaign Finance and Public Disclosure Board (Board). Additional information about how the board makes decisions regarding disclosure is available at https://cfb.mn.gov/citizen-resources/board-programs/overview/government-officials-disclosure/. The Board's Public and Local Officials Handbook is available at https://cfb.mn.gov/pdf/publications/handbooks/Public_officials_handbook.pdf?t=1527106838 (updated 05/16/2018).

Minn. Stat. §10A.07 requires that, if the Commissioner has a financial interest relating to a matter before the agency, they must make this interest known, in writing. The decision-making responsibility regarding the matter must be either assigned by the Governor to another employee, or the Commissioner must abstain from influence over the matter in a manner prescribed by the Board.

Minn. Stat. § 10A.09 requires that statements of economic interest be filed with the Board upon the nomination of the Commissioner, and a supplementary statement must be submitted annually thereafter.

Minn. R. Ch. 7000.0300 further clarifies the need for candor and disclosure by the Commissioner, stating that:

> "In all formal or informal negotiations, communications, proceedings, and other dealings between any person and any member, employee, or agent of the board or commissioner, it shall be the duty of each person and each member, employee, or agent of the board or commissioner to act in good faith and with complete truthfulness, accuracy, disclosure, and candor."

Minn. Stat. § 10A.07, Minn. Stat. § 10A.09, and Minn. R. Ch. 7000.0300 were incorporated into Minnesota's SIP at § 52.1220 per 82 FR 50807.

Summary

Minnesota has no board governing activities related to the CAA. Our statutes and rules address any foreseeable issues of conflict, disclosure, and the public interest as they relate to the MPCA's commissioner. We therefore assert that the above statutory and regulatory authorities fulfill the requirements of Section 128, as it relates to 110(a)(2)(E)(ii).

Conclusions

Based on the information provided in the 2013 iSIP guidance, the 2018 Memo (and associated data updates), and previous iSIP submissions, the MPCA feels confident that the rules and statutes in place in Minnesota are more than sufficient to support our state's ambient air quality program, and to demonstrate that Minnesota is able to meet and comply with the 2015 ozone NAAQS.

Thus, all Section 110(a) iSIP requirements for the 2015 ozone NAAQS, including the interstate transport requirements, are met for the state of Minnesota.

Attachments

Attachment 1: Interstate Transport Modeling for the 2015 Ozone National Ambient Air Quality Standard: Technical Support Document (from LADCO)
Attachment 2: Documentation of ERTAC EGU CONUS Versions 2.7 Reference and CSAPR Update Compliant Scenario (from LADCO)
Attachment 3: Public notice
Attachment 4: Completeness review

MINNESOTA POLLUTION CONTROL AGENCY

Attachment 1:

Interstate Transport Modeling for the 2015 Ozone National Ambient Air Quality Standard

Technical Support Document

Lake Michigan Air Directors Consortium (LADCO) | 54 pages | June 2018

Interstate Transport Modeling for the 2015 Ozone National Ambient Air Quality Standard

Technical Support Document

Lake Michigan Air Directors Consortium
9501 W. Devon Ave., Suite 701
Rosemont, IL 60018

June 1, 2018

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Executive Summary

1 Introduction

The Lake Michigan Air Directors Consortium (LADCO) was established by the states of Illinois, Indiana, Michigan, and Wisconsin in 1989. The four states and EPA signed a Memorandum of Agreement (MOA) that initiated the Lake Michigan Ozone Study and identified LADCO as the organization to oversee the study. Additional MOAs were signed by the states in 1991 (to establish the Lake Michigan Ozone Control Program), January 2000 (to broaden LADCO's responsibilities), and June 2004 (to update LADCO's mission and reaffirm the commitment to regional planning). In March 2004, Ohio joined LADCO. Minnesota joined the Consortium in 2012. LADCO consists of a Board of Directors (i.e., the State Air Directors), a technical staff, and various workgroups. The main purposes of LADCO are to provide technical assessments for and assistance to its member states, and to provide a forum for its member states to discuss regional air quality issues.

1.1 Project Overview

LADCO conducted regional air quality modeling to support the statutory obligations of the LADCO states under Clean Air Section 110(a)(2)(D)(i)(i), which requires states to submit "Good Neighbor" state implementation plans (SIPs). These SIP revisions are plans to prohibit emissions in one state from interfering with the attainment or maintenance of the National Ambient Air Quality Standards (NAAQS) in another state. LADCO used the Comprehensive Air Quality Model with Extensions (CAMx) to support these analyses. The CAMx Anthropogenic Precursor Culpability Assessment (APCA) tool was used to assess the impacts of interstate transport of air pollution on ground level ozone (O_3) concentrations in the Midwest and Northeast U.S.

In support of previous rulemakings (CSAPR, 2011; CSAPR Update, 2016), the U.S. EPA in partnership with states developed a four-step interstate transport framework to address the "Good Neighbor" provisions of the O_3 and $PM_{2.5}$ NAAQS. This framework established the following four steps to identify and mitigate high O_3 concentrations at locations that were at risk of violating the NAAQS in the future: (1) identify monitors with predicted air quality problems in the future year, (2) identify the upwind states that are "linked" through air mass transport to the problem monitors, (3) identify emissions reductions necessary to prevent upwind states from contributing significantly to NAAQS violations at a downwind monitor, and (4) adopt permanent and enforceable measures needed to achieve the identified emissions reductions. Recently, EPA (2018) issued a memo describing a series of potential flexibilities in this four step framework that states could consider in developing a transport SIP.

LADCO used CAMx to predict O_3 concentration in 2023 to address steps (1) and (2) of the four-step interstate transport framework. The LADCO CAMx modeling results are used here to identify O_3 monitoring sites that may have nonattainment or maintenance problems for the 2015 O_3 NAAQS in 2023. The modeling outputs are also used to quantify the contributions of emissions in upwind states to the monitors in downwind states that are projected to have NAAQS attainment problems in 2023. LADCO presents several "flexibilities" in the analytic approaches used to quantify transport and state linkages per a March 2018 U.S. EPA (2018) memo. These alternatives include a comparison between EPA and LADCO CAMx modeling for 2023, exploring the impacts of including or removing water cells in future design values, and exploring the influence of model bias on future design values. All of the alterative analyses presented here are in the context of establishing links between an upwind state and downwind nonattainment or maintenance problems at surface O_3 monitors in the Midwest and Northeast U.S.

This document describes how LADCO used CAMx source apportionment modeling to link upwind and downwind states and to identify upwind emissions sources that significantly contribute to downwind NAAQS attainment issues. The CAMx APCA modeling outputs of this work are being presented to the LADCO states to support the "Good Neighbor" SIP provisions of their 2015 O_3 NAAQS Infrastructure SIPs (iSIP) that are due to EPA in October 2018.

1.2 Organization of the Technical Support Document

This technical support document (TSD) is presented to the LADCO states for estimating year 2023 O_3 design values and source-receptor relationships using the CAMx APCA technique. The TSD is organized into the following sections. Section 0 describes the 2023 Air Quality Modeling Platform that LADCO used to forecast 2023 O_3. Section 0 describes the approach used for estimating Future Ozone Design Values. This section also includes a discussion on the methods used for identifying sites that are forecast to have O_3 NAAQS attainment problems. Section 0 describes the Ozone Source Apportionment modeling used to link source regions with problem monitors in the future year. Section 0 presents the modeling results that the LADCO states can use to support their 2015 O_3 NAAQS Good Neighbor SIPs. This section includes the following results:

- LADCO benchmarking of the EPA modeling platform on the LADCO computing system;
- Future year air quality forecasts from the LADCO CAMx modeling;
- Interstate transport linkages estimated with the LADCO forecasts;
- Alternative attainment test results of future year design values computed with different analysis flexibilities

2 2023 Air Quality Modeling Platform

LADCO based our 2023 O_3 air quality and interstate transport forecasts on the CAMx modeling platform released by the U.S. EPA in October 2017 in support of the Interstate Transport SIPs for the 2008 O_3 NAAQS (US EPA, 2017). The EPA 2023EN modeling platform was projected from a 2011 base year and included a complete set of CAMx inputs, including meteorology, initial and boundary conditions, and emissions data. The future year, or 2023, component of the air quality modeling platform refers to the emissions data only. All other CAMx inputs, including the meteorology data simulated with the Weather Research Forecast (WRF) model, represented year 2011 conditions. LADCO used the majority of the data and software provided by EPA for this platform, with a few exceptions described below.

2.1 Modeling Year Justification

LADCO selected 2011 as a modeling year for this study because CAMx input data for 2011 were widely available and relatively well-evaluated. 2011 had also been identified as a good year for studying O_3 in the Eastern U.S. The US EPA (2015) noted that year 2011 meteorology in the Eastern U.S., including the LADCO region, was warmer and drier than the climatic norm. As compared to other recent years, the summer of 2011 represented typical conditions conducive to high observed O_3 concentrations in the Midwest and Northeast U.S.

Figure 1 shows the 2009-2013 base year O_3 design values for the modeling period selected for this study. Each bubble on the plot represents an Air Quality System (AQS) O_3 surface monitor. Orange, red, and purple colors indicate monitors that were nonattainment (>=71.0 ppbV) for the 2015 O_3 NAAQS during this period. High O_3 concentrations were observed throughout the domain, with particularly high values along the Lake Michigan shoreline, St. Louis, southern Indiana, and the Northeast Corridor from Washington D.C. to Connecticut.

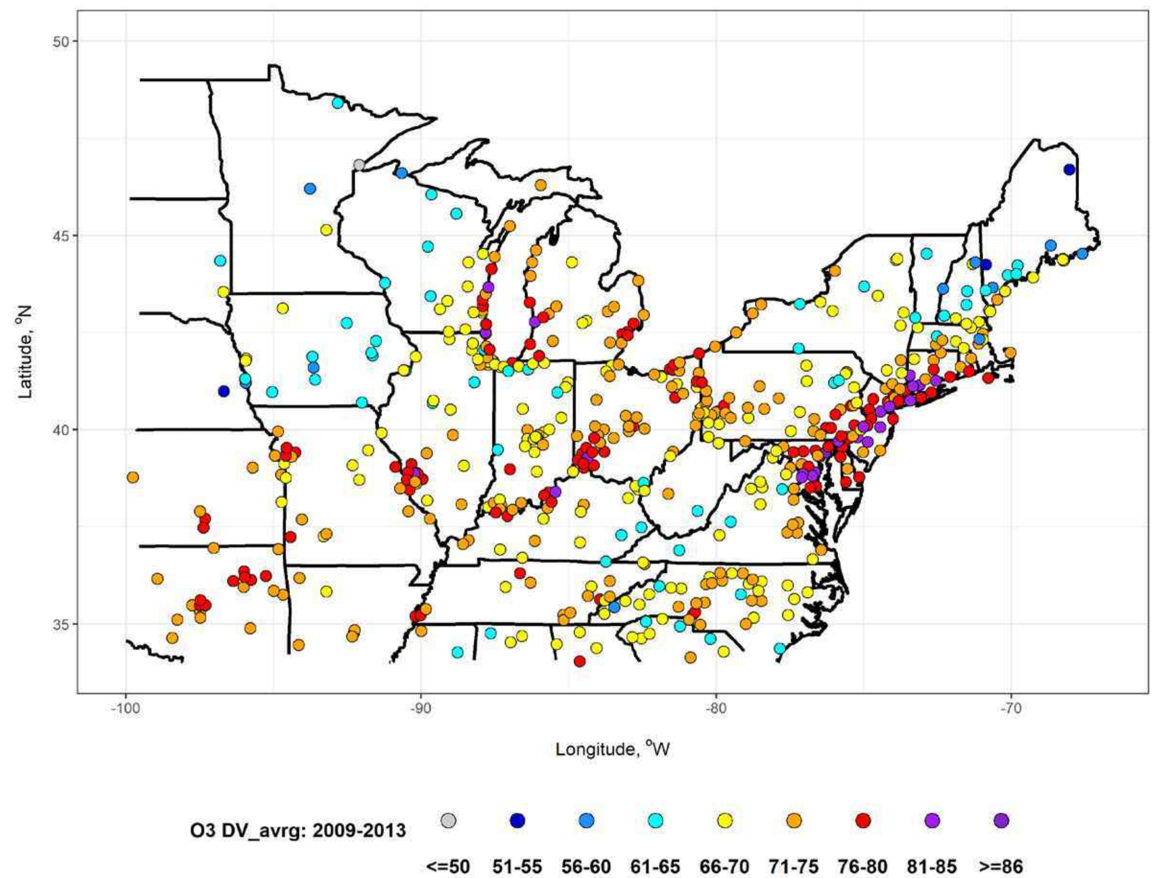

Figure 1. 2011 (2009-2013) O_3 design values for the eastern U.S.

The triennial National Emissions Inventory (NEI) also synchronized with 2011. Since its first release in 2014, the NEI2011 has undergone several revisions, with the most recent updates to version 6.3 released in October 2017 as part of the U.S. EPA's final 2008 O_3 NAAQS interstate transport assessment (US EPA, 2017). The 2011-based emissions modeling platforms are currently the best available national-scale datasets for simulating air quality in the U.S. The U.S. EPA used version 6.3 of the NEI2011-based emissions modeling platform for their preliminary assessment of O_3 transport for the 2015 O_3 NAAQS (US EPA, 2016). Given recent use of 2011-based data for evaluating interstate transport by the U.S. EPA and the lack of a more contemporary national emissions modeling platform, LADCO believes that using 2011-based data and emissions projections are justified for assessing interstate O_3 transport.

LADCO selected 2023 as the future project year based on the availability of data from EPA. EPA selected 2023 for 2015 O_3 NAAQS modeling because it "aligns with the anticipated attainment year for moderate O_3 nonattainment areas" (US EPA, 2018).

2.2 Air Quality Model Configuration

LADCO based the CAMx air quality modeling platform for this study on the configuration that the U.S. EPA used to support both their October 2017 memo on

Interstate Transport SIPs for the 2008 O_3 NAAQS (US EPA, 2015) and their December 2016 technical support document on a preliminary assessment of Interstate Transport for the 2015 O_3 NAAQS (US EPA, 2016). LADCO used CAMx v6.40 (Ramboll-Environ, 2016) as the photochemical grid model (PGM) for this study. CAMx is a three-dimensional, Eulerian air quality model that simulates the chemical transformation and physical transport processes of air pollutants in the troposphere. It includes capabilities to estimate the concentrations of primary and secondary gas and particle phase air pollutants, and dry and wet deposition, from urban to continental spatial scales. As CAMx associates source-level air pollution emissions estimates with air pollution concentrations, it can be used to design and assess emissions reduction strategies pursuant to NAAQS attainment goals.

LADCO selected CAMx for this study because it is a component of recent U.S. EPA modeling platforms for investigating the influence of interstate transport on O_3, and because it has source apportionment capabilities for quantifying air pollution source-receptor relationships. As CAMx is a component of U.S. EPA studies with a similar scope to this project, LADCO was able to leverage the data and software elements that are distributed with U.S. EPA regulatory modeling platforms. Using these elements saved LADCO significant resources relative to building a modeling platform from scratch. CAMx is also instrumented with source apportionment capabilities that allowed LADCO to investigate the sources of air pollution impacting O_3 monitors within and downwind of the LADCO region.

Figure 2 shows the U.S. EPA transport modeling domain for the continental U.S. A 12-km uniform grid (CONUS12) covers all of the continental U.S. and includes parts of Southern Canada and Northern Mexico. The domain has 25 vertical layers with a model top at about 17,550 meters (50 mb). LADCO used the same U.S. EPA 12-km domain for this project because it supported the use of meteorology, initial and boundary conditions, and emissions data that were freely available from U.S. EPA.

As the focus of this study is on O_3, LADCO used CAMx to simulate the O_3 season. LADCO simulated May through September 2011 as individual months using 10-day model spin-up periods for each month.

Complete details of the EPA 2011 CAMx simulation, including a performance evaluation of the model are available from the U.S. EPA (2016).

Figure 2. CAMx 12-km modeling domain (CONUS12)

2.3 Meteorology Data

LADCO used the U.S. EPA 2011 WRF data for this study (US EPA, 2017). The U.S. EPA used version 3.4 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2011 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation (FDDA) configuration are detailed the EPA 2008 Transport Modeling technical support document (US EPA, 2015). U.S. EPA prepared the WRF data for input to CAMx with version 4.3 of the WRFCAMx software.

2.4 Initial and Boundary Conditions

LADCO used 2011 initial and boundary conditions for CAMx generated by the U.S. EPA from the GEOS-Chem Global Chemical Transport Model (US EPA, 2017). EPA generated hourly, one-way nested boundary conditions (i.e., global-scale to regional-scale) from a 2011 2.0 degree x 2.5 degree GEOS-Chem simulation. Following the convention of the U.S. EPA O_3 transport modeling, year 2011 GEOS-Chem boundary conditions were used by LADCO for modeling 2023 air quality with CAMx.

2.5 Emissions Data

The 2023 emissions data for this study were based on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform (US EPA, 2017b). US EPA generated this platform for their final assessment of Interstate Transport for the 2008 O_3 NAAQS. Updates from earlier 2011-based emissions modeling platforms included a new engineering approach for forecasting emissions from Electricity Generating Units (EGUs). The U.S. EPA made several changes to the base 2011 and forecasted 2023 emissions in the "EN" platform relative to the earlier "EL" platform (US EPA, 2017b).

LADCO replaced the EGU emissions in the EN platform with 2023 EGU forecasts estimated with the ERTAC EGU Tool version 2.7[1]. The ERTAC EGU Tool provided more accurate estimates of the growth and control forecasts for EGUs in the Midwest and Northeast states than the EPA approach used for the "EN" platform. LADCO used the EPA EN Platform emissions estimates for all other inventory sectors.

2.5.1 Electricity Generating Unit Emissions

The ERTAC EGU model for growth was developed around an activity pattern matching algorithm deliberately built to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low cost software that air quality planning agencies could use for developing EGU emissions projections. States needed a transparent model that was numerically stable and did not change dramatically with small changes in inputs. A key feature of the model includes data transparency, where all inputs are publicly available. The code is also operationally transparent, which includes extensive documentation, open source code, and a diverse user community to support new users of the software.

Operation of the model is straightforward given the complexity of the projection calculations and inputs. The model imports base year Continuous Emissions Monitoring data from US EPA and sorts the data from peak to the lowest generation hour. It applies hour specific growth rates that include peak and off peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. Finally, future year controls are applied to the emissions estimates and tests for reserve capacity, final reporting, and conversion to a SMOKE ready modeling files is done.

ERTAC EGU has distinct advantages over other growth methodologies because it is capable of generating hourly future year estimates which are key to understanding O_3 episodes. Additionally it does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Full documentation for the ERTAC Emissions model and 2.7 simulations are available through the MARAMA website[1].

2.5.2 LADCO 2023 Emissions Summary

The tables and figures in this section summarize the emissions used in the LADCO and EPA 2023 CAMx simulations. Table 1 shows the annual NOx and SO_2 EGU emissions for the base year (2011), ERTAC EGU 2023, and the EPA EN 2023 inventories. LADCO state and regional total emissions are presented in this table. Figure 3 and Figure 4 summarize the NOx and SO_2 emissions graphically for the LADCO states. The ERTAC EGU 2023 and EPA EN 2023 EGU emissions estimates differ across the LADCO states. ERTAC estimates 3,314 tons/year more NOx and 8,152 tons/year more SO_2 for IL EGUs than the EPA EN projections. ERTAC estimates 12,567 tons/year more NOx and 24,356

[1] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

tons/year more SO_2 in OH than the EPA EN projections. The MI EGU projections are lower from ERTAC by 5,731 tons/year NOx and 23,434 tons/year SO_2 than the EPA EN projections. The differences for IN EGUs are mixed with ERTAC projecting 2,083 tons/year less NOx and 34,393 tons/year more SO_2 than the EPA EN projections.

Regionally, ERTAC projects lower NOx but higher SO_2 emissions in the Northeast and Southeast relative to the EPA EN projections. ERTAC EGU projects higher NOx and SO_2 emissions across the CENSARA and WESTAR states relative to the EPA 2023 projections.

While these annual summaries mask the fine scale temporal differences between the EGU projection methodologies, in general the differences in O_3 projections between the LADCO and EPA simulations (Section 5.4.1,) are consistent with the differences in annual total NOx emissions between the EGU projections used in each simulation. The LADCO 2023 simulation generally forecasted lower O_3 in the Northeast and Southeast than the EPA 2023 EN simulation, consistent with the lower EGU NOx emissions predicted by ERTAC EGU in these regions.

Table 1. EGU sector emissions annual NOx and SO_2 totals (tons/year)

State/ Region	NEIv6.3 2011		ERTAC2.7 2023		EPA EN 2023	
	NOx	SO2	NOx	SO2	NOx	SO2
LADCO States						
IL	142,582	432,902	34,078	81,899	30,764	73,747
IN	228,895	725,652	61,314	114,865	63,397	80,472
MI	149,802	452,352	27,977	43,818	33,708	67,252
MN	62,033	77,134	14,600	14,904	21,919	15,606
OH	204,874	1,168,733	50,140	114,289	37,573	89,933
WI	62,585	183,179	15,829	10,826	15,419	7,623
Regional Totals						
LADCO	850,771	3,039,951	203,938	380,601	202,780	334,634
MARAMA/ OTC	441,004	941,121	84,533	197,712	97,903	112,429
SESARM	1,079,697	2,564,573	291,058	320,508	328,132	297,145
CENSARA	827,715	1,867,451	274,253	624,243	221,846	406,174
WESTAR	841,803	769,929	298,107	234,680	201,044	185,593

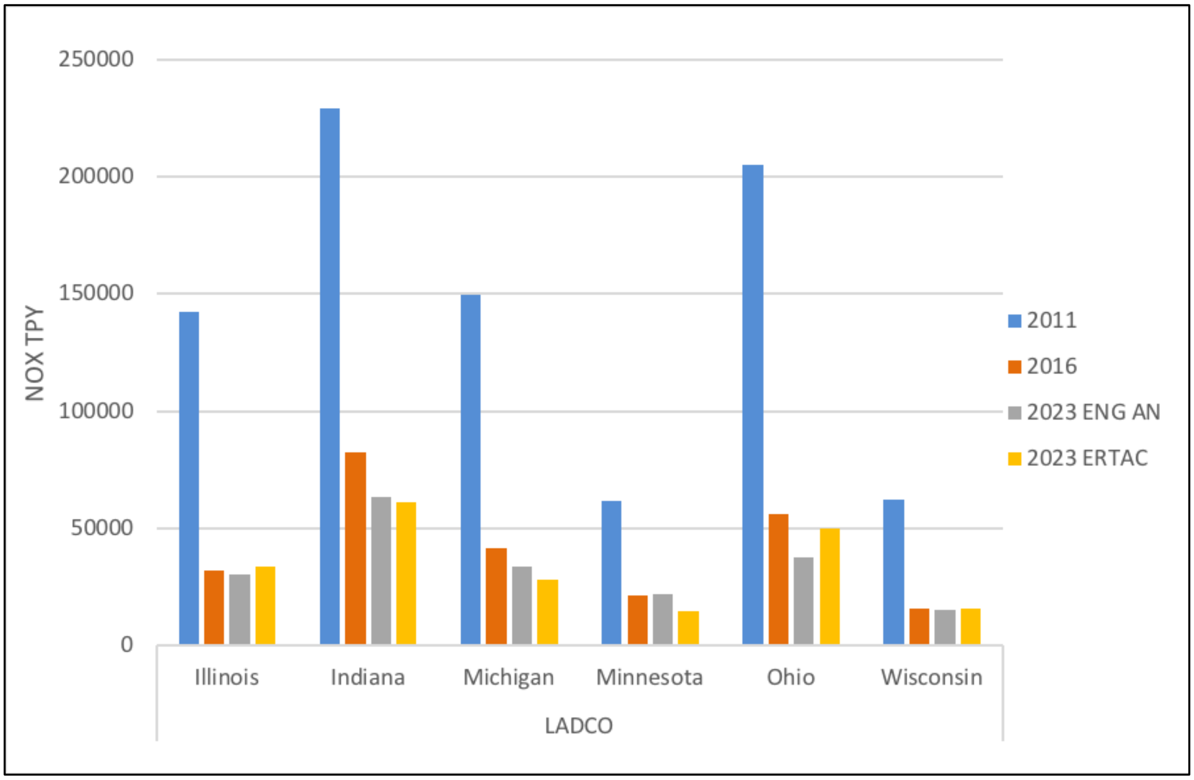

Figure 3. EGU NOx emissions comparison (tons/year)

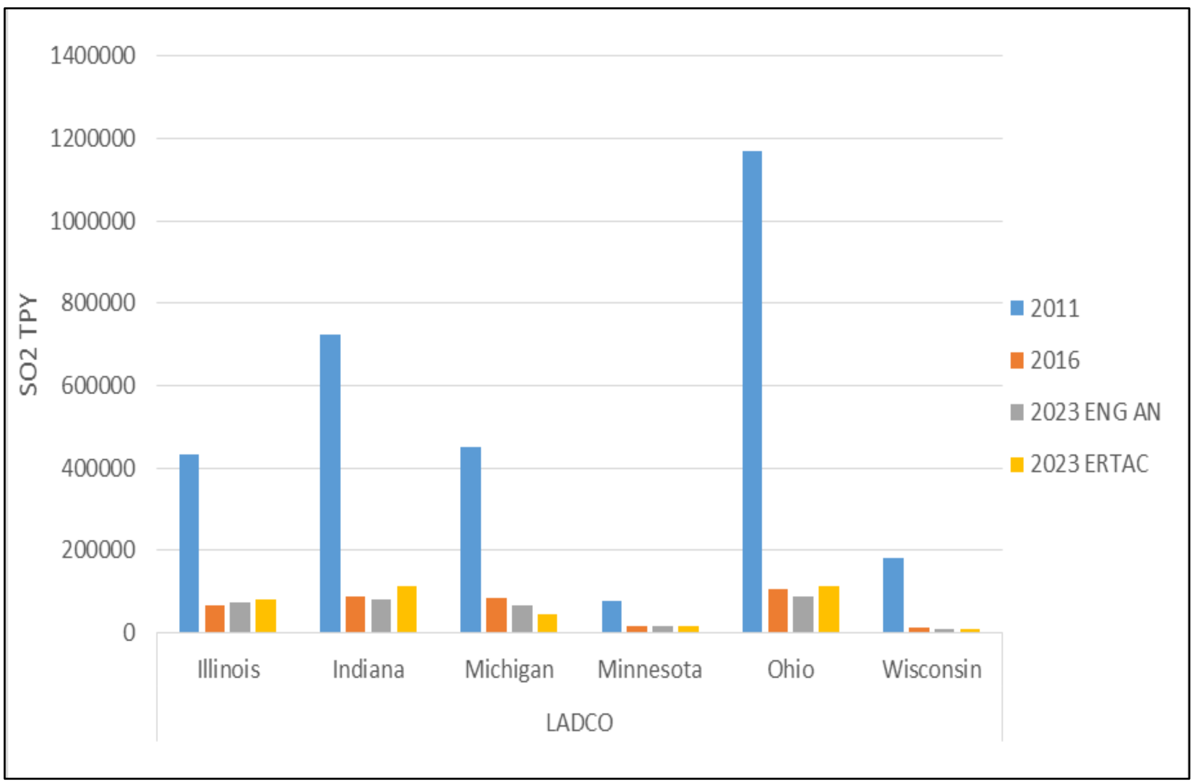

Figure 4. EGU SO_2 emissions comparison (tons/year)

Table 2. Total O_3 season day emissions for the LADCO 2023 simulations (tons/day)

State/ Region	CO	NOx	VOC	SO_2	NH_3	$PM_{2.5}$
LADCO States						
IL	607,125	143,052	497,088	44,492	47,348	41,223
IN	513,679	110,536	327,044	65,725	61,564	28,785
MI	632,948	102,683	609,349	43,644	39,374	25,621
MN	984,896	95,232	661,274	16,987	103,977	82,507
OH	687,300	115,544	424,614	58,947	62,778	32,843
WI	417,474	69,094	504,084	13,832	74,005	20,940
Region Totals						
LADCO	3,843,423	636,140		243,628	389,046	231,919
MARAMA/ OTC	2,635,608	503,960		123,407	115,592	77,799
SESARM	7,159,486	974,250		294,760	442,054	420,764
CENSARA	5,046,349	903,500		289,903	635,259	390,384
WESTAR	10,584,500	1,289,397		179,681	709,998	778,381

2.6 U.S. EPA Modeling Platform Benchmarking

LADCO benchmarked both the U.S. EPA 2011 and 2023 CAMx "EN" modeling platforms on our computing cluster. The benchmark simulation used the exact same CAMx version and configuration as was used by U.S. EPA. The purpose of these simulations was to confirm that LADCO correctly installed and configured the EPA data and software on our cluster. We needed to verify our installation of the modeling platform on the LADCO computing cluster in order to take advantage of the extensive vetting and evaluation of the platform by U.S. EPA. By reproducing the U.S. EPA CAMx modeling results on the LADCO computer, we inherited the model evaluation completed by the U.S. EPA, thereby validating the use of the platform for this study.

LADCO verified the platform installation on our computing systems by comparing the results of the U.S. EPA and LADCO 2011 and 2023 EN simulations. We simulated the entire O_3 season, with spin up, for both 2011 and 2023 for comparison with the U.S. EPA modeling. The LADCO benchmarking results for the 2011 simulation are presented in Section 5.1.

2.7 Evaluation of the LADCO 2023 CAMx Simulation

As future year air quality forecasts cannot be compared to observations for evaluation, LADCO relied on the model performance evaluation (MPE) conducted by the U.S. EPA on the base modeling platform that we used for this study (US EPA, 2016). In addition to the MPE for the base year CAMx simulation, the U.S. EPA reported full MPE results for the 2011 WRF modeling (US EPA, 2014) used to drive the CAMx simulations.

LADCO compared the 2023 O_3 forecasts that we generated in this study against the 2023 U.S. EPA "EN" platform results. We compared daily average and daily maximum 1-

hour and 8-hour O_3 concentrations at monitoring locations in the Midwest and Northeast. The purpose of this comparison was to evaluate the changes in the LADCO forecasts that result from the change in the EGU emissions forecasts used for this study relative to the U.S. EPA 2023 modeling. The comparisons of the 2023 O_3 forecasts for the LADCO and EPA CAMx simulations are presented in Section 5.2.

3 Future Year Ozone Design Values

LADCO followed the U.S. EPA Draft Guidance for Attainment Demonstration Modeling (US EPA, 2014b), herein referred to as the U.S. EPA Guidance, to calculate future year design values (DVFs) for monitors in the Midwest and Northeast U.S. As we used a base year of 2011, we estimated the base year design values (DVCs) using surface observations for the years 2009-2013. LADCO estimated the DVFs with version 1.2 of the Software for Modeled Attainment Test Community Edition (SMAT-CE)[2]. SMAT-CE was configured to use the average O_3 concentration in a 3x3 matrix around each monitor across the 10 highest modeled days, per the U.S. EPA Guidance.

SMAT-CE uses a four step process to estimate DVFs:

1. Calculate DVC for each monitor
   - For O_3, the design values is a three-year average of the 4th highest daily maximum 8 hour average O_3 ($MDA8_4$):

$$DV_{2011} = (MDA8_{4,2009} + MDA8_{4,2010} + MDA8_{4,2011})/3$$

   - Weighted 5-year average of design values centered on the base model year (2011):

$$DVC_{2011} = (DV_{2011} + DV_{2012} + DV_{2013})/3$$

2. Find top 10 base year modeled days surrounding each monitor
   - Find ten days with the highest base year modeled MDA8 from within a 3x3 matrix of grid cells surrounding each monitor
   - Only days with modeled MDA8 >= 60 ppb are used
3. Calculate relative response factor (RRF) for each monitor
   - Calculate averaged MDA8 for the base and future years from the average of the values in the 3x3 matrix in each of the selected top 10 modeled days
   - Calculate the RRF as the ratio of the future to base year averaged MDA8:

$$RRF = MDA8_{2023,avg}/MDA8_{2011,avg}$$

4. Calculate DVF for each monitor

$$DVF = RRF * DVC_{2011}$$

Following from the U.S. EPA March 2018 Ozone Transport Memo, we also calculated DVFs to account for the influence of surface water on CAMx performance over coastal regions. The alternative DVF calculation approach presented by EPA excludes from the 3x3 matrix around a monitor those model grid cells that are dominated by water (> 50% water by landuse coverage). In the case of water-dominated grid cells that include a monitor, the monitor cell is included in the alternative calculation.

[2] https://www.epa.gov/scram/photochemical-modeling-tools

Additional details of the EPA approaches that LADCO used for calculating DVFs are provided in the U.S. EPA's Ozone Transport Modeling Assessments (US EPA 2018; US EPA, 2016; US EPA, 2015).

LADCO employed another alternative for calculating DVFs that considers the skill of CAMx in reproducing the base year observations near a monitor. The standard EPA DVF approach uses the ten modeled days with the highest MDA8 concentrations around a monitoring location to estimate the relative response factor (RRF) for a monitor. In this approach, the top ten days are selected irrespective of the ability of the model to reproduce the observations during the selected days. Table 3 illustrates an example of the MDA8 modeled and observed concentrations at the Chiwaukee Prairie, WI monitor on the top 10 modeled days from the LADCO 2011 CAMx simulation. The table shows that 6 of the top 10 modeled days correspond with days that are in the top 10 observed days (yellow shading); two of the top 10 modeled days are in the top 15-20 observed days (orange shading). Four of the top 10 modeled days also have percent biases greater than 15%, with one day exhibiting a model overprediction of greater than 134%.

Table 3. Chiwaukee Prairie, WI (AQS ID: 550590019) top 10 modeled MDA8 days

Date	OBS*	MOD*	BIAS*	BIAS%
7/4/2011	79.25	105.63	26.38	33.29%
7/9/2011	83.00	101.03	18.03	21.72%
7/24/2011	41.63	97.69	56.06	134.69%
7/30/2011	51.75	91.22	39.47	76.26%
9/1/2011	96.00	91.21	-4.79	4.99%
7/17/2011	88.25	82.95	-5.30	6.01%
7/10/2011	77.38	78.89	1.52	1.96%
7/23/2011	74.88	77.36	2.49	3.32%
6/7/2011	68.38	73.93	5.55	8.12%
9/2/2011	71.13	73.75	2.62	3.69%

*Units = ppbV

The alternative DFV calculation explored by LADCO filtered the model results by bias, selecting the top 10 model days only from days when the bias falls below a certain threshold. As the EPA Modeling Guidance (2014b) sets the model performance goal for O_3 at 15% mean bias, LADCO excluded days with a bias greater than 15% in an alternative "bias filtered" DVF calculation. Table 4 extends the example for the Chiwaukee Prairie, WI monitor by showing the top 10 modeled days with absolute modeled bias less than 15%. Filtering out the high bias days results in all of the top 10 modeled days corresponding to days in which the observations were in the top 20 concentrations of all days. With this approach, not only will more of the highest concentration observed days be included in the RRF calculation but the days that are included will be those in which the model was able to better reproduce the observations. In exhibiting better skill on these days, the model has a better chance of capturing the causes of the high O_3 and subsequently simulating the sensitivity of changes in emissions on the O_3 concentrations.

Table 4. Chiwaukee Prairie, WI top 10 modeled MDA days with bias <= 15%

Date	OBS	MOD	BIAS	BIAS%
9/1/2011	96.00	91.21	-4.79	4.99%
7/17/2011	88.25	82.95	-5.30	6.01%
7/10/2011	77.38	78.89	1.52	1.96%
7/23/2011	74.88	77.36	2.49	3.32%
6/7/2011	68.38	73.93	5.55	8.12%
9/2/2011	71.13	73.75	2.62	3.69%
8/31/2011	70.38	72.49	2.12	3.01%
6/6/2011	75.29	71.73	-3.56	4.73%
8/2/2011	75.50	69.47	-6.03	7.98%
7/15/2011	65.75	67.48	1.73	2.63%

*Units = ppbV

The DVFs at nonattainment and maintenance monitors in the Midwest and Northeast U.S. from the three alternative comparisons: EPA vs LADCO, LADCO water vs no water, and LADCO bias filtered are presented in Section 0.

LADCO used the DVFs to identify nonattainment and maintenance sites in 2023 using the most recent 3-year monitored design values (2015-2017) per the CSAPR Update methodology (CSAPR Update, 2016). Under this methodology sites with average DVFs that exceed the 2015 NAAQS (71 ppb or greater) and that are currently measuring nonattainment would be considered nonattainment receptors in 2023. Further, monitoring sites with maximum DVFs that exceeds the NAAQS would be considered a maintenance receptor in 2023. Under the CSAPR Update, maintenance only receptors include both those sites where the average DVF is below the NAAQS, but the maximum DVF is above the NAAQS; and monitoring sites with average DVFs above the NAAQS but with DVCs that are below the NAAQS.

The sites that LADCO identified through this process as having potential for nonattainment and maintenance designations for the 2015 O_3 NAAQS in 2023 were the focus of our source apportionment analyses. LADCO used the CAMx source apportionment APCA technique to assess the impacts of upwind sources on nonattainment and maintenance monitors in downwind states. Section 5.3 presents the results of the linkages of LADCO states to downwind maintenance and nonattainment monitors using a threshold of 1% of the NAAQS (0.70 ppb).

4 Ozone Source Apportionment Modeling

LADCO used the CAMx Anthropogenic Precursor Culpability Assessment (APCA) tool to calculate emissions tracers for identifying upwind sources of O_3 at downwind monitoring sites. We selected the APCA technique because it more appropriately associates O_3 formation to anthropogenic sources than the CAMx Ozone Source Apportionment Technique (OSAT). If any anthropogenic emissions are involved in a reaction that leads to O_3 formation, even if the reaction occurs with biogenic VOC or NOx, APCA tags the O_3 as anthropogenic in origin.

In the LADCO 2023 CAMx Source Apportionment modeling protocol (LADCO, 2018), we presented a configuration to tag both source regions and emissions inventory sectors for our APCA modeling. In the final APCA configuration, we primarily tagged only source regions in order to better leverage both the EPA 2023 EN CAMx modeling platform and to optimize the simulation on the LADCO computing cluster. We consolidated the 54 source tracers used by EPA into 32 tracers (Figure 5) based on an analysis of the linkages in the EPA modeling results. We maintained explicit O_3 tracers for only those states that had CSAPR linkages (at least 0.7 ppb MDA8) to nonattainment and maintenance monitors in the latest EPA 2023 modeling (US EPA, 2018). For the rest of the states, such as New England, most of the Southeast, and the West, we grouped them into single tracers for computational efficiency. Following from the EPA 2023 EN modeling platform, in addition to each source region, LADCO created explicit tags for fire emissions, biogenic emissions, offshore emissions, tribal emissions, Canada/Mexico emissions, and Initial/Boundary Conditions.

LADCO used the EPA 2023 EN data processing methods for preparing emissions for the APCA simulation. EPA developed a technique to convert all of the emissions data, including non-point sources such as biogenics and onroad mobile, to CAMx point source formatted data. Tagging of the emissions by state FIPs code is done during the emissions processing sequence to ensure that all of the emissions are properly attributed to the state from which they originate. This tagging is done to avoid the conventional problem in source apportionment modeling of mismatches between grid cell-based source regions and actual political boundaries. Additional details of the EPA emissions tagging approach are in U.S. EPA (2016).

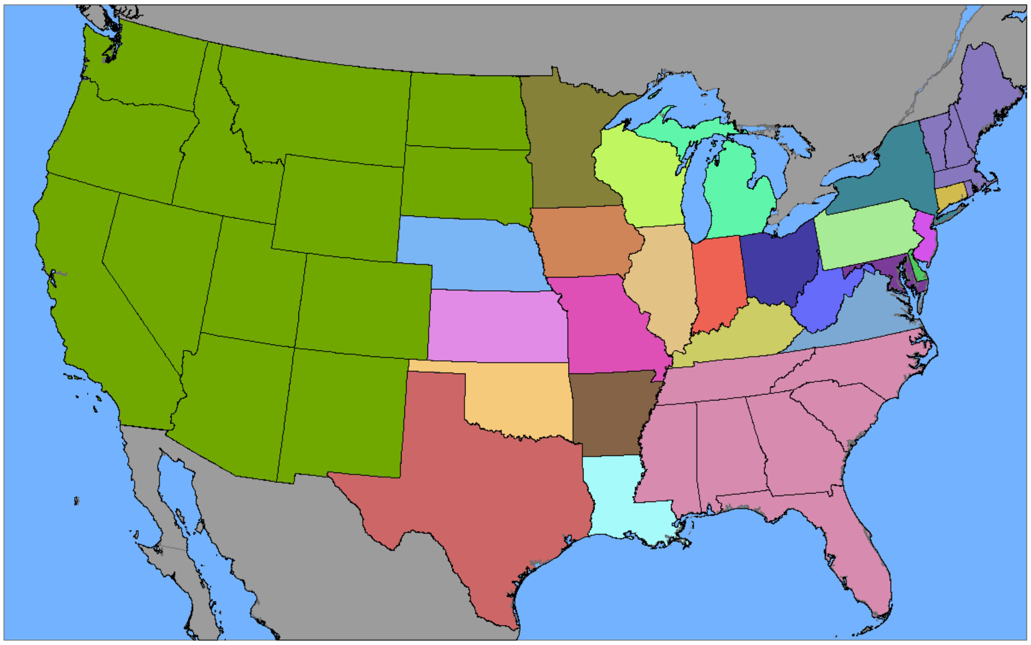

Figure 5. CAMx APCA Source Regions

We used the CAMx APCA results to calculate an O_3 contribution metric for each potential nonattainment and maintenance monitor in the Midwest and Northeast U.S. (US EPA, 2016). The contribution metric is designed to provide a reasonable representation of individual states and sources to the design values at downwind monitors in future years. In particular, per the CSAPR methodology, downwind monitors are considered to be linked to upwind sources if a modeled contribution assessment shows impacts at a monitor that equal or exceeds 1% of the NAAQS. For the 2015 O_3 NAAQS, source regions (and inventory sectors) that contribute 0.70 ppb or more to a monitor would be considered significant contributors to a nonattainment or maintenance monitor.

In Section 0 LADCO presents alternative design values and source apportionment modeling results for different transport modeling flexibilities. This section shows how the 2023 contributions and design values change with different EGU emissions, considerations of whether or not water cells are included in DVF calculations, and considerations of the model bias in the DVF calculations.

5 Results and Discussion

5.1 EPA 2011 EN Platform Benchmarking Results

LADCO simulated the entire O_3 season (May 1 – September 30, 2011) with CAMx using the EPA 2011 EN modeling platform. The purpose of the benchmarking simulation was to demonstrate that LADCO could closely reproduce the EPA results using the same model inputs and configuration used by EPA on a different computing infrastructure. By demonstrating that LADCO can reproduce the EPA results, we establish the validity of the EPA modeling platform on the LADCO systems and inherit the full model performance evaluation and vetting process used by EPA for the 2011 EN platform (US EPA, 2016).

Figure 6 and Figure 7 compare O_3 season MDA8 O_3 between the LADCO 2011 (LADCO_2011en) and the EPA 2011 EN simulations at the locations of all of the AQS and CASTNET monitors in the CONUS12 domain, respectively. The data for these figures are paired in space and time, meaning that each symbol on the plot represents a comparison of the two simulations at the same monitor on the same day. While there is some variability between the two runs (AQS maximum absolute MDA8 difference is 7.06 ppbV), the runs are not expected to be exactly the same due to numerical differences in computing architectures between the EPA and LADCO computing systems. For 194,953 AQS data pairs, the Pearson correlation coefficient for the LADCO and EPA simulations is 0.99969 and the coefficient of determination (R^2) is 0.999, indicating that the two simulations produced very similar results. The comparison of predicted O_3 concentrations at the rural CASTNET monitors shows similar correspondence between the runs ($R^2 = 0.999$).

Figure 8 shows a timeseries comparison of MDA8 O_3 for the EPA and LADCO 2011 simulations at a single monitor location. Each data point on this figure represents the daily MDA8 for the two simulations at the Chiwaukee Prairie monitor in southeastern Wisconsin. This figure also shows a very close correspondence between the EPA (blue line) and LADCO (red line) simulations relative to the observations (black line).

The close correspondence in predicted O_3 between the EPA and LADCO 2011 simulations illustrated in these figures is consistent across states, monitoring networks and time periods. These results demonstrate the LADCO was able to effectively port the EPA 2011 EN modeling platform to the LADCO computing cluster and use the platform as the basis for projecting future year O_3 concentrations. Despite the numerical differences introduced into the 2011 EN simulation by the LADCO computing architecture, LADCO will forecast 2023 O_3 on the same computing architecture as the 2011 benchmark simulation to ensure comparability between the LADCO 2011 and 2023 simulations.

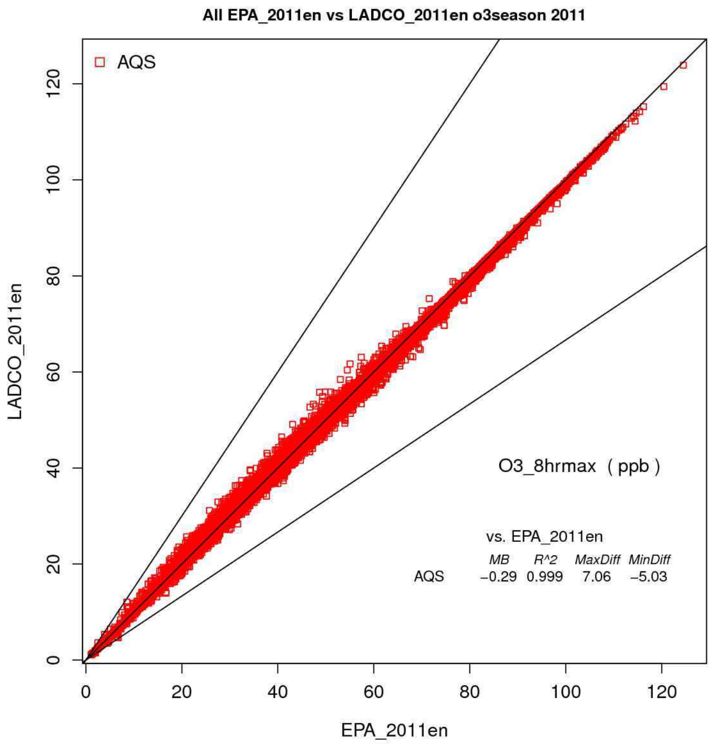

Figure 6. LADCO vs EPA 2011 EN summer season AQS MDA8 O_3

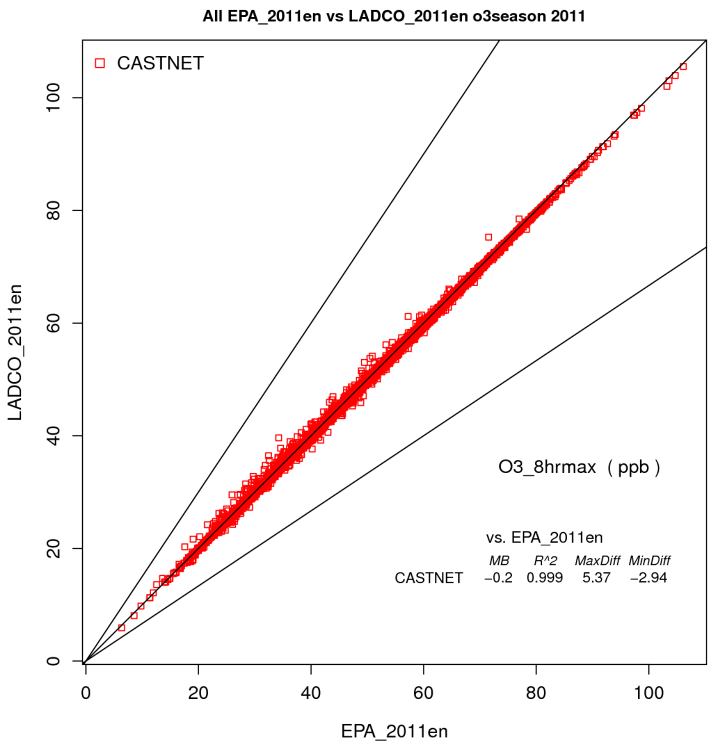

Figure 7. LADCO vs EPA 2011 EN summer season CASTNET MDA8 O_3

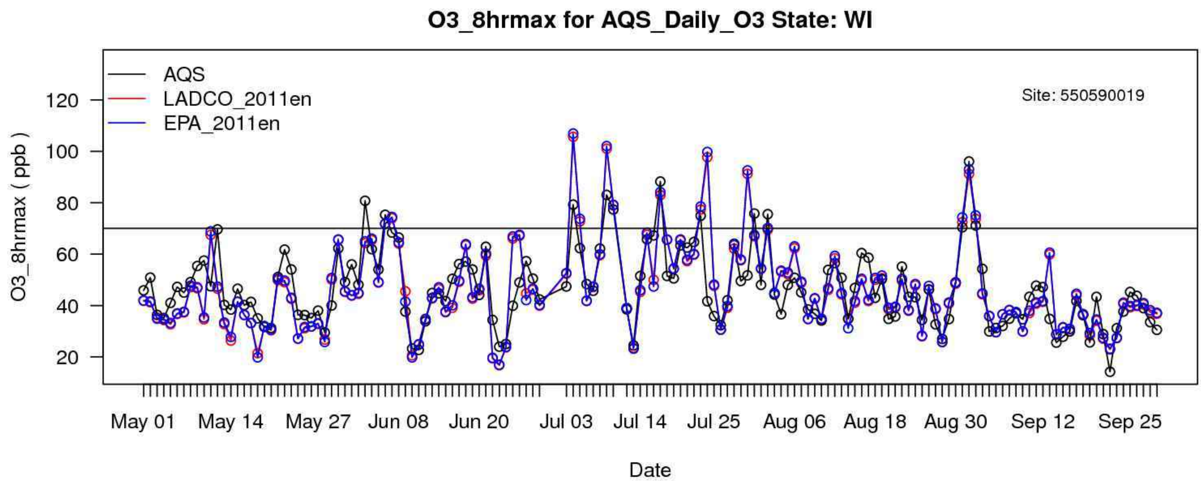

Figure 8. Timeseries of MDA8 O_3 at Chiwaukee Parairie, WI comparing EPA and LADCO 2011 simulations.

5.2 LADCO 2023 Air Quality Projections

LADCO modified the emissions in the EPA 2023 EN platform to create a LADCO 2023 modeling platform (see Section 2.5). The LADCO 2023 simulation forecasts air quality for the continental U.S. using the best available information for North American emissions, including EGU emissions forecasts from the ERTAC v2.7 model. Figure 9 shows the O_3 season (May through September) maximum of MDA8 O_3 for the LADCO and EPA 2023 CAMx simulations on the CONUS12 modeling domain. Figure 10 shows the difference in O_3 season maximum (LADCO – EPA) between the two simulations. Cool colors indicate that the EPA simulation forecasts higher O_3 than the LADCO simulation; warm colors indicate higher O_3 in the LADCO forecast. In general, the EPA simulation predicts higher O_3 in the Midwest, Northeast, Gulf Coast, and Pacific Coast states; the LADCO simulation predicts higher O_3 in the Four Corners region and Central Arkansas. Note that the trends shown in these figures mask finer temporal resolution features (i.e., hourly and daily) that also exist between the LADCO and EPA 2023 simulations.

Figure 11 and Figure 12 compare O_3 season MDA8 O_3 between the LADCO 2023 (LADCO_2023en) and the LADCO 2011 (LADCO_2011en) simulations at the locations of all of the AQS and CASTNET monitors in the CONUS12 domain, respectively. As both of these simulations were run on the LADCO computing cluster, the differences in the runs are due entirely to the emissions projections from 2011 to 2023. The LADCO simulation forecasts MDA8 O_3 to decrease in 2023 by an average of 5.34 ppbV across all AQS monitors and by an average of 6.13 ppbV across all CASTNET monitors. These changes are similar to the EPA forecasts, which estimated average decreases in MDA8 O_3 of 5.23 ppbV at the AQS monitors and 6.15 ppbV at the CASTNET monitors.

Figure 13 shows the O_3 DVFs and RRFs from the LADCO 2023 simulation. LADCO generated these results with SMAT-CE using the standard US EPA attainment test configuration (top 10 modeled days, 3x3 cell matrix around the monitor, including water cells). ***The LADCO 2023 CAMx simulation forecasts that no monitors in the Midwest or Northeast will be nonattainment (orange) for the 2015 O_3 NAAQS.*** The highest mean DVF in these regions is the Suffolk County, NY (AIRS ID: 36103002) monitor at 69.8 ppbV; the highest maximum DVF is Fairfield, CT (AIRS ID: 90019003) at 72.4 ppbV. The RRF plot indicates that the largest reductions (25-30%) in DVFs are forecasted to occur in Chicago, Louisville, Cincinnati, and North Carolina. Regionally, the Mid-Atlantic and Northeast are forecasted to experience widespread reductions in O_3 DVFs in the range of 20-25%.

Figure 14 shows the LADCO DVFs zoomed in on the Lake Michigan region. This plot highlights that only two Lake Michigan shoreline monitors, Sheboygan Co., WI and Allegan Co., MI are at or near maintenance of the 2015 O_3 NAAQS. A third monitor in Wayne Co., MI is also forecast to be near maintenance status.

Table 5 presents the average and maximum DVFs for the near nonattainment and maintenance monitors in the Midwest and Northeast. The red highlighted values indicate forecasted maintenance status for the 2015 O_3 NAAQS. The Kohler Andre monitor in Sheboygan, WI (AIRS ID: 551170006) is the only forecasted maintenance monitor in the LADCO region with a maximum DVF of 71.5 ppbV.

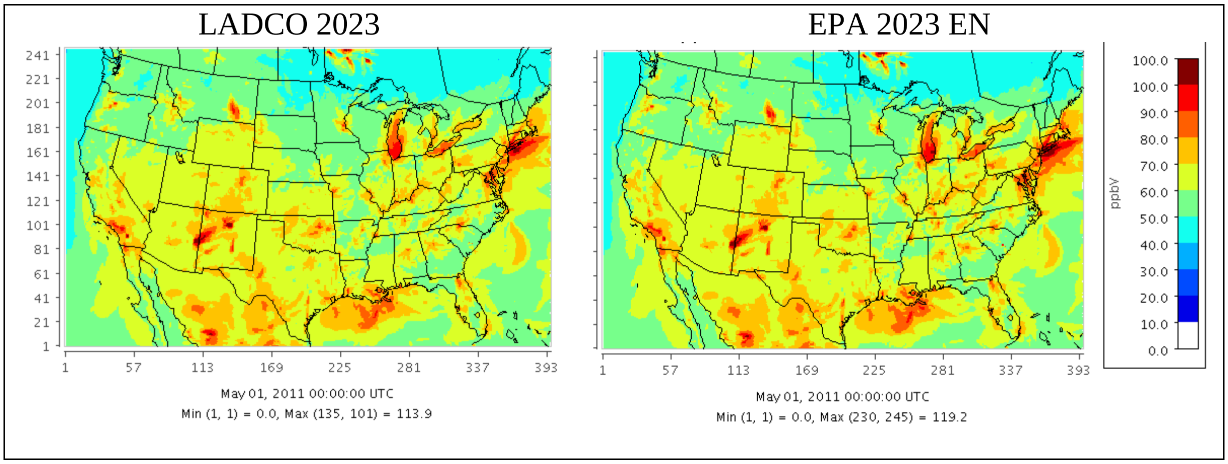

Figure 9. LADCO and EPA CAMx May - Sept maximum 2023 MDA8 O_3

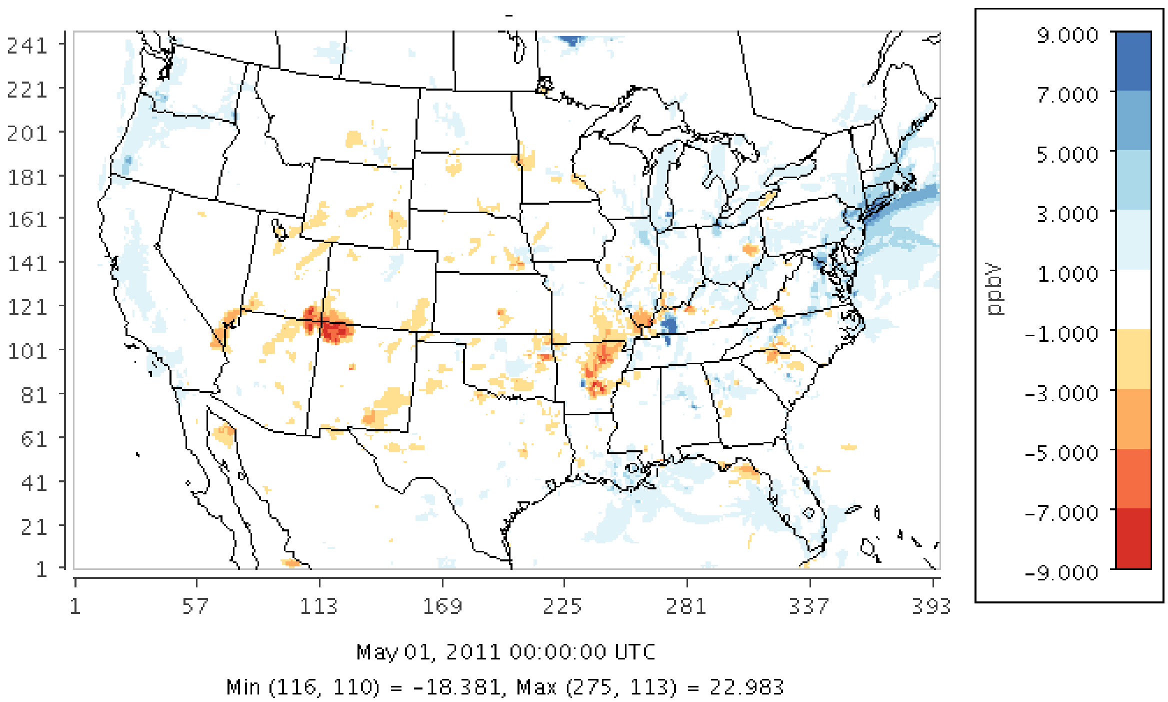

Figure 10. CAMx May - Sept difference (LADCO-EPA) in maximum 2023 MDA8 O_3

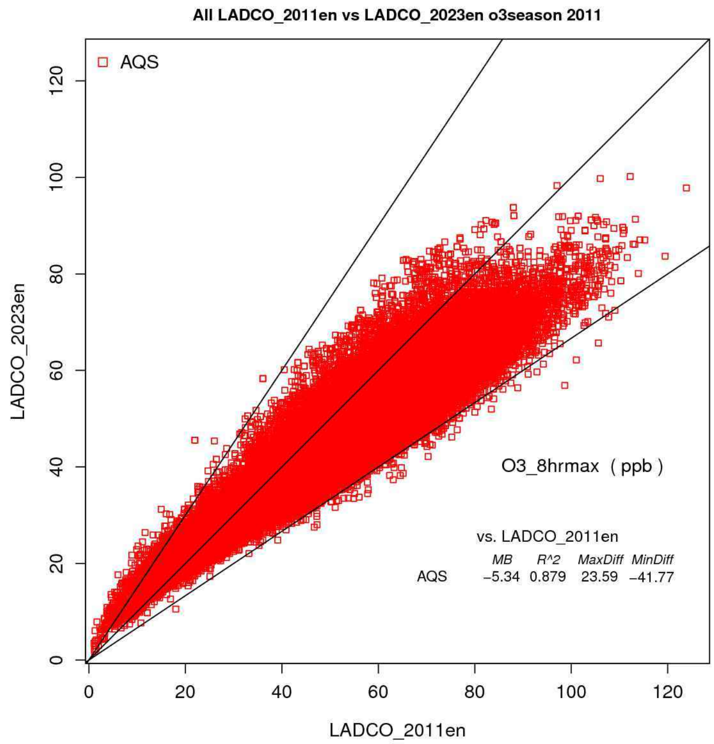

Figure 11. LADCO 2023 vs 2011 summer season AQS MDA8 O_3

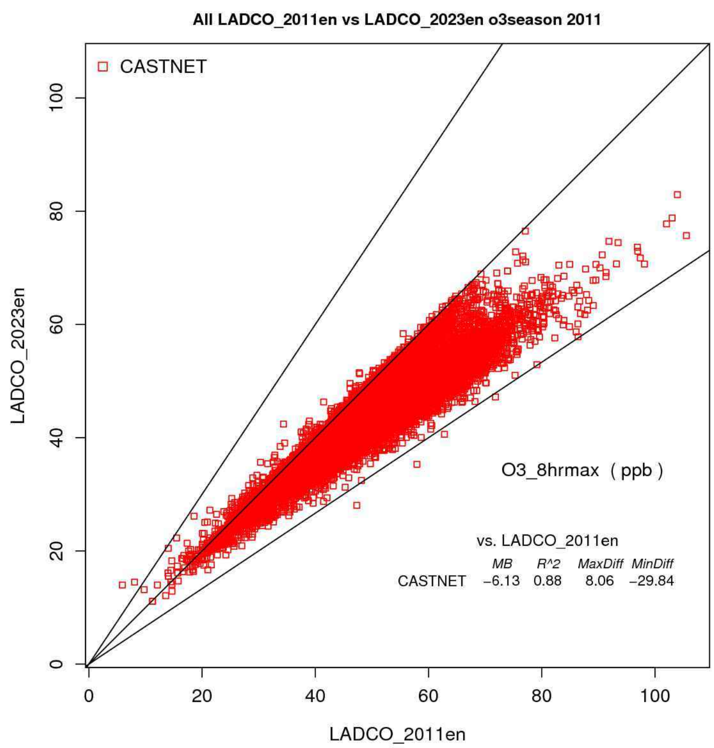

Figure 12. LADCO 2023 vs 2011 summer season CASTNET MDA8 O_3

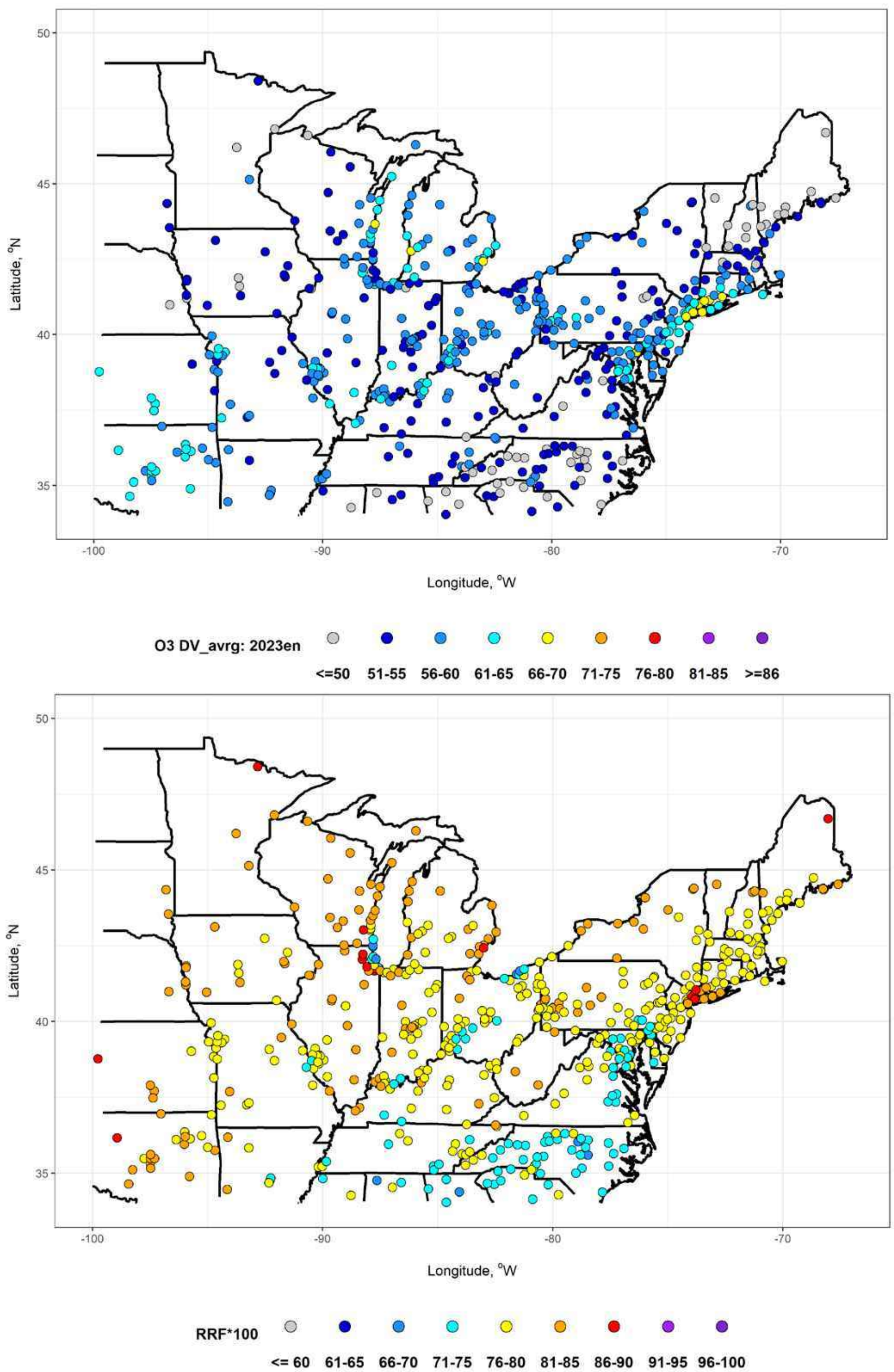

Figure 13. Future year O_3 design values (top) and relative response factors (bottom) calculated with water cells included from the LADCO 2023 CAMx simulation.

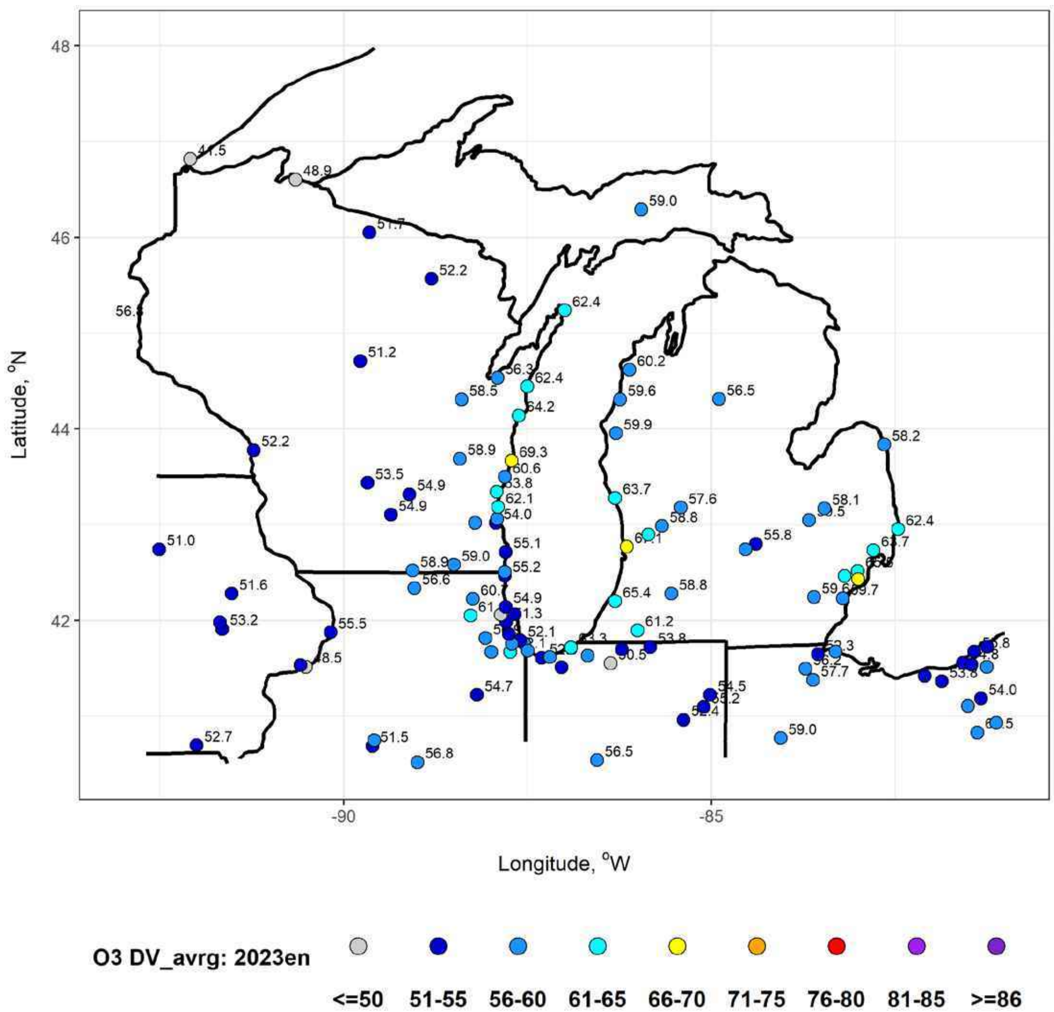

Figure 14. Future year O_3 design values calculated with water cells included from the LADCO 2023 CAMx simulation; Lake Michigan zoom.

Table 5. LADCO 2023 O_3 design values at nonattainment and maintenance monitors in the Midwest and Northeast

AQS ID	County	ST	LADCO 2023 3x3 avrg	LADCO 2023 3x3 max	2009-2013 3x3 avrg	2009-2013 3x3 max
361030002	Suffolk	NY	69.8	71.3	83.3	85.0
90019003	Fairfield	CT	69.6	72.4	83.7	87.0
240251001	Harford	MD	69.4	71.8	90.0	93.0
551170006	Sheboygan	WI	69.3	71.5	84.3	87.0
360850067	Richmond	NY	69.1	70.6	81.3	83.0
90099002	New Haven	CT	67.9	70.5	85.7	89.0
90013007	Fairfield	CT	67.8	71.6	84.3	89.0
261630019	Wayne	MI	67.7	69.7	78.7	81.0
360810124	Queens	NY	67.5	69.2	70.0	71.0
90010017	Fairfield	CT	67.2	69.4	78.0	80.0
260050003	Allegan	MI	67.1	69.8	80.3	83.0
550790085	Milwaukee	WI	62.1	65.1	78.3	82.0

5.3 Interstate Transport Linkages

Table 6 shows the MDA8 O_3 DVF CSAPR linkages between states and monitors estimated by the LADCO 2023 simulation. These linkages are derived from the standard EPA attainment test that includes water cells in the 3x3 matrix surrounding each monitor. The linkages in Table 6 are provided for the same monitors highlighted in Table 5. While there are no projected nonattainment monitors in the LADCO 2023 simulation, the maintenance monitors are highlighted in red text. The states with contributions that equal or exceed 1% of the 2015 O_3 NAAQS (0.70 ppbV) are highlighted with yellow shading.

As described above, the only monitor in the LADCO region projected to be in maintenance for the 2015 O_3 NAAQS by the LADCO 2023 modeling is the Kohler Andre monitor in Sheboygan, WI with a maximum DVF of 71.5 ppbV. Illinois is the highest contributing source region linked to this monitor (14.13 ppbV) followed by WI (9.54 ppbV), IN (6.24 ppbV), MI (2.15 ppbV), and TX (2.02 ppbV). While all of the LADCO states, with the exception of MN, have CSAPR-significant linkages to the maintenance monitors in the Northeast, OH has the largest single contribution to a monitor outside of the LADCO region (2.88 ppbV at Harford, MD). Despite projected attainment, the Wayne Co., MI monitor experiences the largest influence from outside of the U.S. (CNMX = 3.22 ppbV) of all of the monitors in Table 6.

Figure 15 through Figure 23 show the 2023 ozone season maximum of the CAMx APCA O_3 tracers for the LADCO states, Texas, Offshore (commercial marine) sources, and Canada+Mexico. While these plots do not indicate the conditions in which these maximum values occur (i.e., on high or low O_3 days), they do show the maximum magnitudes and spatial extents of the influence of each state on regional O_3 concentrations. Figure 15 shows that CAMx estimated that IL contributes a domain maximum O_3 concentration of 70.8 ppbV. The maximum influence of IL emissions on O_3 is near Chicago and over Lake Michigan. Within the LADCO region, IL sources have the greatest influence on O_3 concentrations in southeast WI, northwest IN, and the Lower Peninsula of MI. CAMx estimated that IL contributes a maximum of 2-4 ppbV O_3 to the coastal areas in the Northeast and up to 8 ppbV O_3 as far south as the Louisiana Gulf Coast.

Figure 16 shows that CAMx estimated that IN contributes a domain maximum 46.6 ppbV O_3. The highest contributed O_3 concentrations from IN sources are in southern Lake Michigan. Within the LADCO region, IN sources have the greatest influence on O_3 concentrations in southern IL, southern MI, and central OH. CAMx estimated similar O_3 impacts for IN as for IL in the coastal areas in the Northeast and in the Gulf Coast.

The CAMx estimates for MI O_3 tracers in Figure 17 show a domain maximum contribution of 38.4 ppbV with the greatest impacts over Lakes Michigan, Ontario, and Erie. Within the LADCO states, MI sources have the greatest influence on O_3 concentrations in northern IN and OH. MI is also estimated to have a slightly greater impact on O_3 in the Northeast than both IL and IN, with maximum O_3 tracer concentrations of 4-6 ppbV extending off the Northeast coast.

Figure 18 shows that the maximum O_3 impact from MN sources is estimated to be 50.1 ppbV and occurs around the Twin Cities. MN has the greatest regional influence on O_3 concentrations in northern WI. The MN O_3 tracers are estimated to extend as far south as Dallas and east into central PA.

Figure 19 shows that OH sources have the greatest impact on O_3 over Lake Erie with a domain maximum tracer concentration of 63.1 ppbV. Within the LADCO region, OH sources are estimated to have the greatest impact on O_3 in eastern IN and southeastern MI. As the easternmost LADCO state, OH is estimated to have the greatest impact on O_3 in the Northeast, with maximum OH tracer concentrations of 8-10 ppbV extending to the Northeast

As shown in Figure 20, WI sources are estimated by CAMx to have the greatest impact on O_3 concentrations along the WI shoreline of Lake Michigan. The highest WI O_3 tracer concentration of 41.2 ppbV occurs over Lake Michigan off the southeast coast of the state. Within the region, WI sources have the greatest influence on O_3 concentrations in western MI and the far northeast corner of IL. CAMx estimates that WI sources influence O_3 concentrations as far away as northeast TX and along the Northeast U.S. coast by a maximum range of 2-4 ppbV.

Figure 21 shows that TX sources are estimated to impact O_3 concentrations in all of the LADCO states. The great influence from TX sources on O_3 in the region are estimated by CAMx to be in southern IL and southern WI by a maximum of 8-10 ppbV. The O_3 tracer from offshore sources shown in Figure 22 has relatively small impacts on O_3 in the LADCO states. Figure 23 shows that sources in Canada and Mexico are estimated by CAMx to influence O_3 concentrations through most of the Continental U.S. The largest influence in the LADCO region is near the Canadian border in eastern MI. Canadian emissions are estimated to impact most of the LADCO states by a seasonal maximum of 2-10 ppbV.

Table 6. MDA8 O_3 (ppbV) DVF (with WATER) CSAPR linkages to monitors in the LADCO 2023 simulation

AIRS ID	361030002	90019003	240251001	551170006	360850067	90099002	90013007	261630019	360810124	90010017	260050003
STATE	NY	CT	MD	WI	NY	CT	CT	MI	NY	CT	MI
2009-13 AVG	83.3	83.7	90.0	84.3	81.3	85.7	84.3	78.7	78.0	80.3	82.7
2009-13 MAX	85.0	87.0	93.0	87.0	83.0	89.0	89.0	81.0	80.0	83.0	86.0
2023 AVG	69.8	69.6	69.4	69.3	69.1	67.9	67.8	67.7	67.5	67.2	67.1
2023 MAX	**71.3**	**72.4**	**71.8**	**71.5**	70.6	70.5	**71.6**	69.7	69.2	69.4	69.8
IL	0.65	0.62	0.85	14.13	0.85	0.42	0.71	1.83	0.69	0.39	18.31
WI	0.24	0.17	0.23	9.54	0.31	0.24	0.23	0.94	0.36	0.25	1.73
IN	0.75	0.78	1.36	6.24	0.97	0.46	0.94	2.18	0.64	0.45	6.61
OH	1.71	1.43	2.88	0.60	2.17	1.08	1.77	3.72	1.63	1.02	0.19
MI	0.95	0.49	0.66	2.15	1.01	0.65	0.66	19.68	1.12	0.47	3.20
MN	0.16	0.11	0.12	0.27	0.13	0.17	0.15	0.30	0.16	0.17	0.11
IA	0.19	0.15	0.23	0.48	0.24	0.14	0.16	0.40	0.24	0.11	0.70
MS	0.39	0.36	0.58	1.34	0.50	0.27	0.38	0.70	0.36	0.21	2.46
AR	0.14	0.15	0.22	0.52	0.16	0.09	0.15	0.25	0.11	0.08	1.87
LA	0.11	0.10	0.24	0.98	0.17	0.07	0.11	0.15	0.13	0.05	0.68
TX	0.58	0.45	0.86	2.02	0.79	0.40	0.45	0.86	0.56	0.32	2.41
OK	0.34	0.22	0.38	1.38	0.41	0.24	0.23	0.52	0.31	0.17	1.39
KS	0.19	0.14	0.24	0.64	0.24	0.13	0.14	0.36	0.17	0.09	0.75
CT	0.57	3.48	0.01	0.00	0.24	6.14	3.81	0.00	0.57	8.20	0.00
NY	16.47	13.76	0.46	0.02	6.65	14.00	12.69	0.06	13.92	15.92	0.00

NJ	7.96	7.22	0.33	0.00	10.04	5.24	6.39	0.00	7.89	5.87	0.00
PA	5.96	6.12	4.87	0.18	9.45	5.01	5.82	0.17	5.53	4.77	0.05
DE	0.18	0.31	0.11	0.00	0.41	0.31	0.30	0.00	0.34	0.16	0.00
MD	1.03	1.52	17.79	0.02	1.61	1.30	1.46	0.02	1.33	1.00	0.01
WV	0.75	1.04	2.39	0.27	1.55	0.57	1.02	0.20	0.69	0.65	0.11
VA	0.89	1.72	3.96	0.07	1.56	1.20	1.30	0.15	1.26	1.15	0.04
SE	0.82	1.24	1.97	1.37	1.59	0.68	1.23	0.80	0.80	0.75	1.75
KY	0.51	0.76	1.62	0.58	0.93	0.32	0.89	0.64	0.40	0.36	0.59
WRAP	0.98	0.60	1.01	1.12	1.04	0.68	0.64	1.18	0.87	0.55	1.13
CNMX	1.75	1.26	0.84	0.60	1.54	1.64	1.34	3.22	1.89	1.64	0.56
OFFSHORE	2.02	2.64	3.35	0.89	1.85	4.16	2.88	0.31	2.17	1.46	0.47
TRIBAL	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRE	0.28	0.32	0.45	0.54	0.37	0.21	0.33	0.40	0.22	0.20	0.89
ICBC	18.71	18.14	15.20	15.97	16.89	17.65	17.25	22.22	18.21	17.09	12.32
BIOG	4.12	3.82	5.31	7.18	5.01	3.85	3.90	6.14	4.20	3.27	8.44

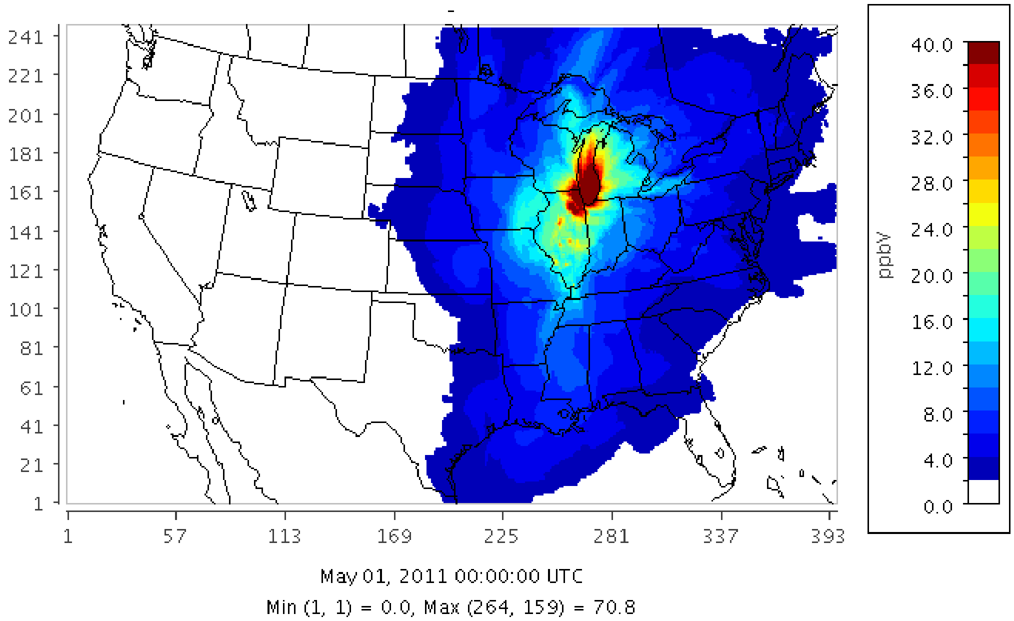

Figure 15. Ozone season maximum CAMx APCA O_3 tracers – Illinois

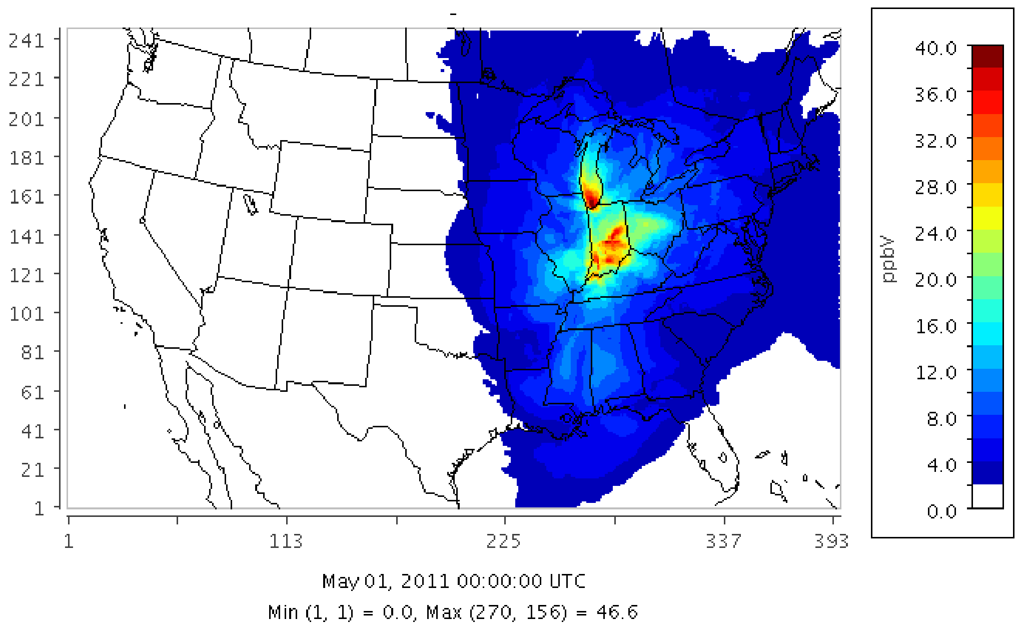

Figure 16. Ozone season maximum CAMx APCA O_3 tracers – Indiana

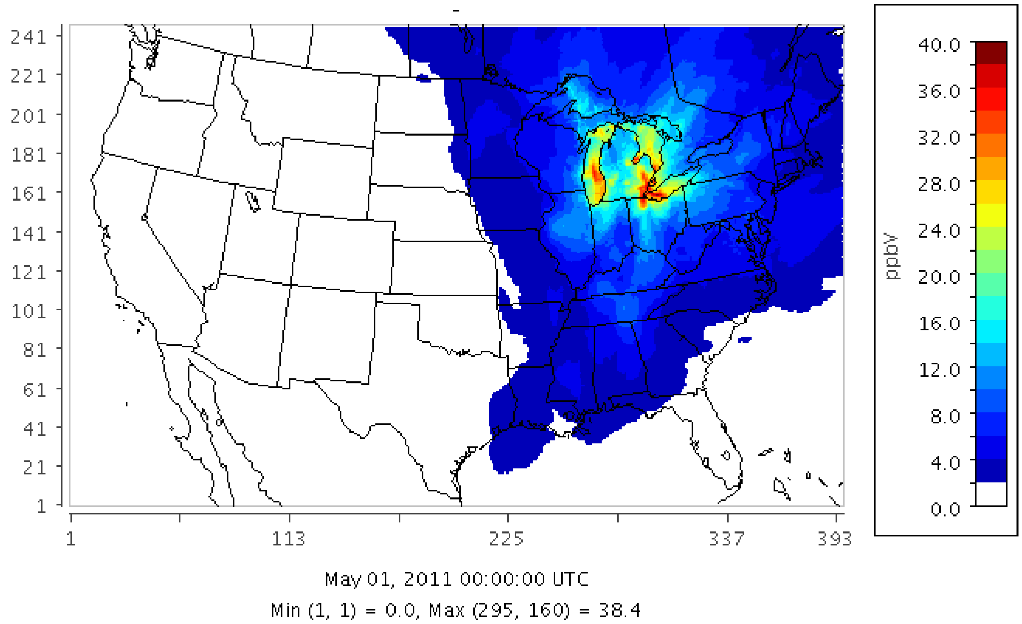

Figure 17. Ozone season maximum CAMx APCA O_3 tracers – Michigan

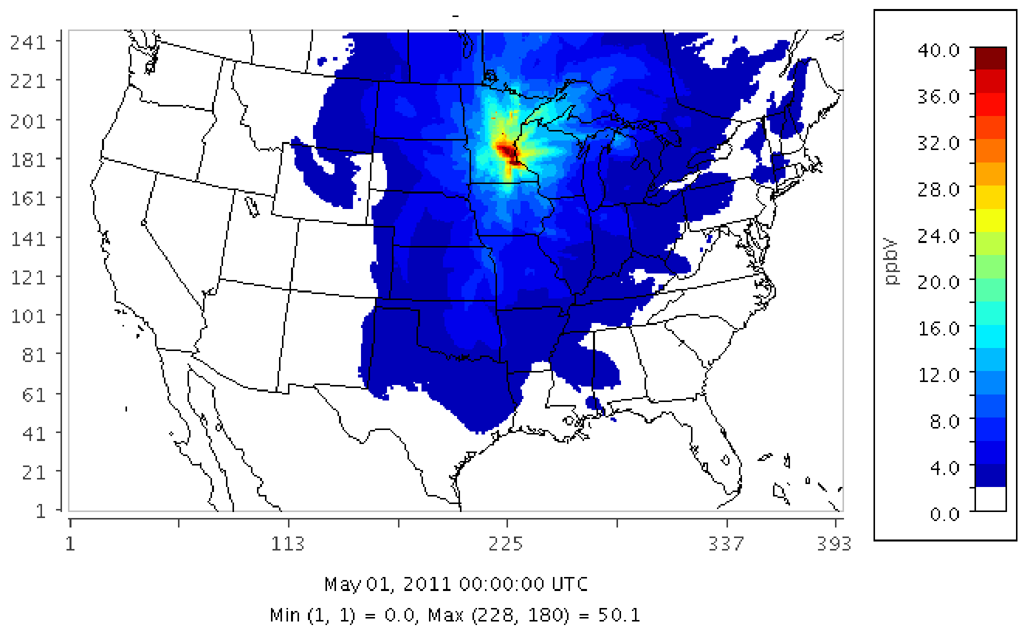

Figure 18. Ozone season maximum CAMx APCA O_3 tracers – Minnesota

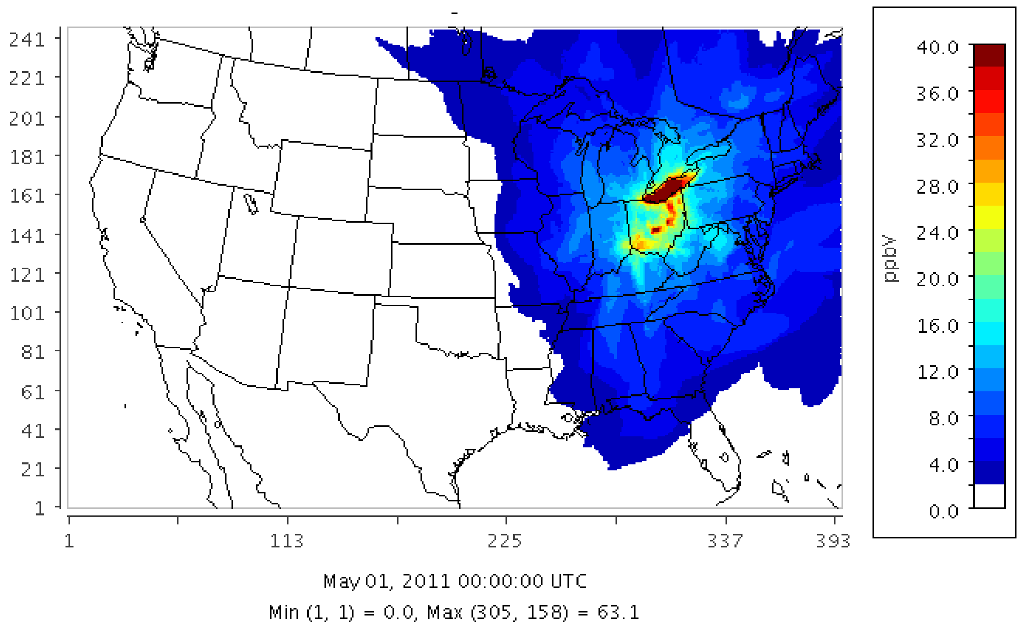

Figure 19. Ozone season maximum CAMx APCA O_3 tracers – Ohio

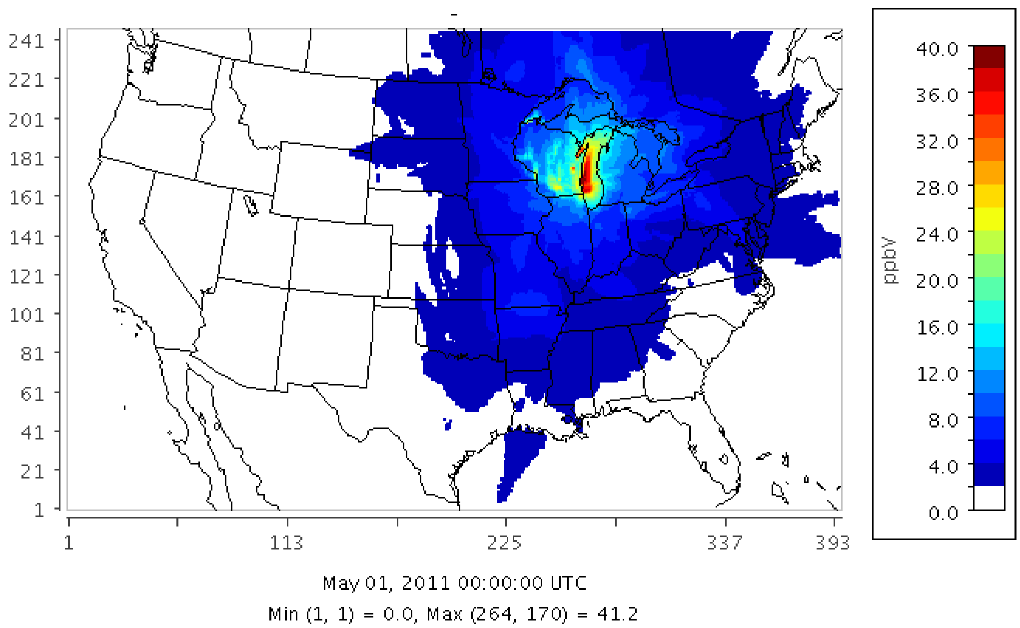

Figure 20. Ozone season maximum CAMx APCA O_3 tracers – Wisconsin

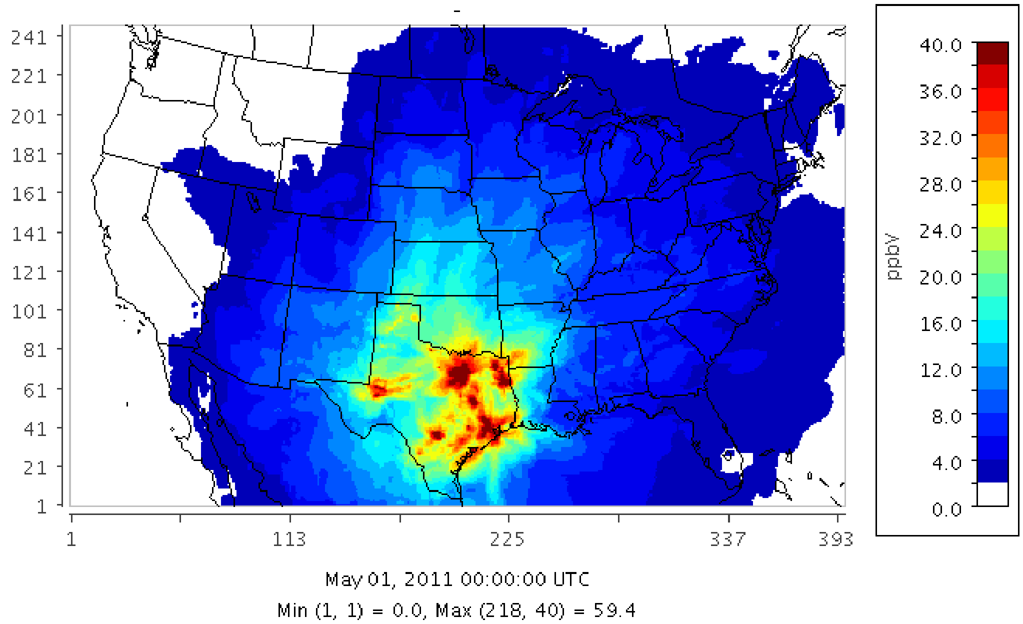

Figure 21. Ozone season maximum CAMx APCA O_3 tracers – Texas

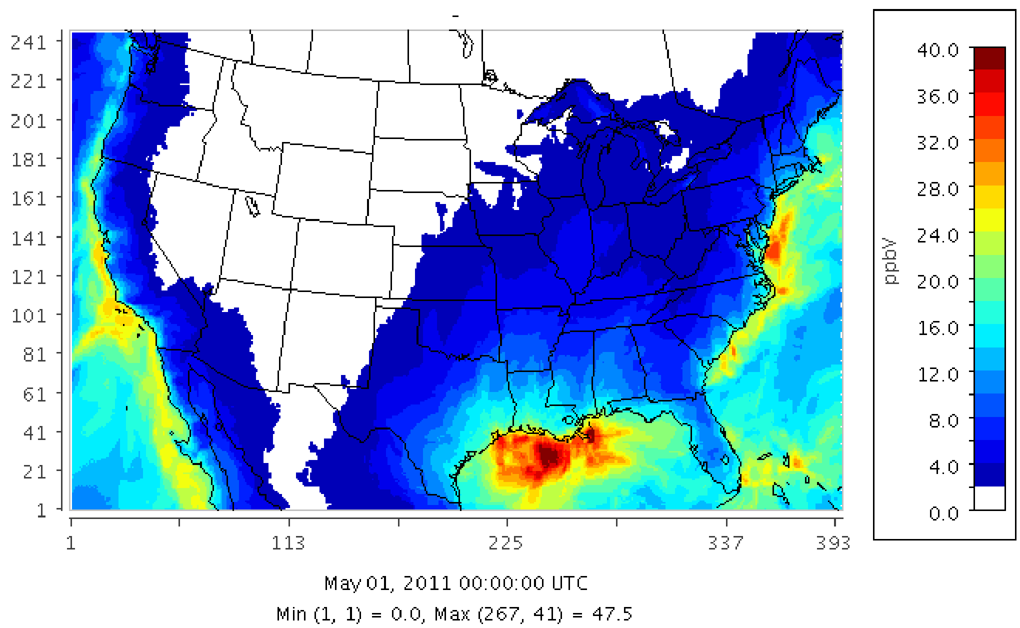

Figure 22. Ozone season maximum CAMx APCA O_3 tracers – Offshore

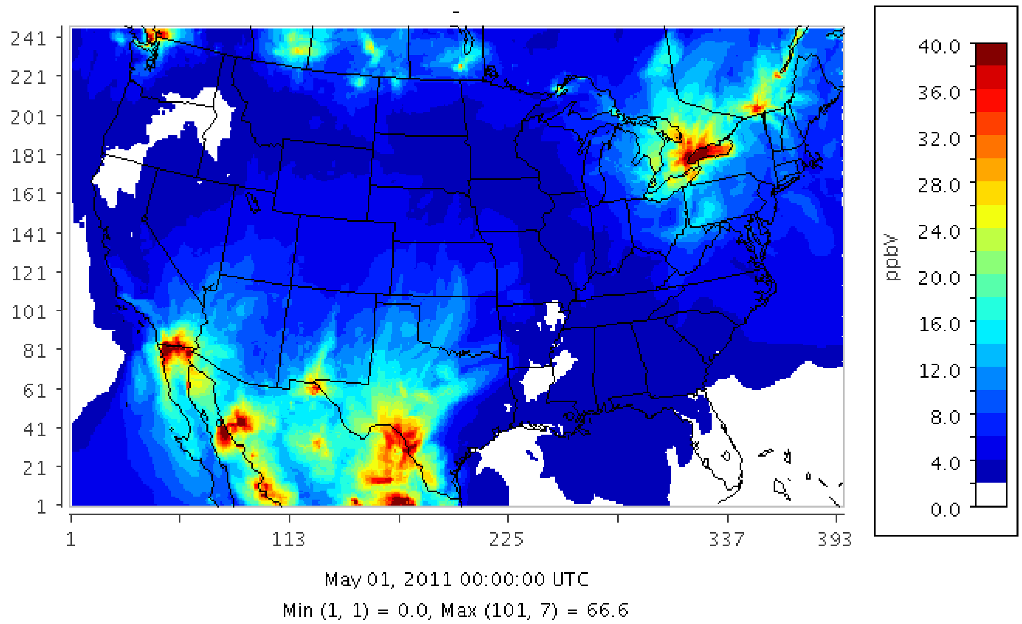

Figure 23. Ozone season maximum CAMx APCA O_3 tracers – Canada and Mexico

5.4 Interstate Transport Assessment Flexibilities

In March 2018 EPA released a memo (US EPA, 2018) the described a series of flexibilities that states could consider in developing Good Neighbor SIPs for the 2015 O_3 NAAQS. In this section LADCO presents a series of alternatives for calculating DVFs. We compare the results against the standard US EPA attainment test configuration (top 10 modeled days, 3x3 cell matrix around the monitor, including water cells) to demonstrate how the air quality projections and conclusions may change with each approach.

5.4.1 Alternative Power Sector Modeling

The "[u]se of alternative power sector modeling consistent with EPA's emissions inventory guidance" is presented in the Analytics section of EPA's March 2018 memo as a flexibility to consider in preparing a Good Neighbor SIP. This flexibility supports LADCO's use of the ERTAC EGU model for projecting EGU emissions to 2023. As described in Section 2.5.1, we consider the emissions projections from ERTAC EGU to be more representative of the sources in the Midwest and Northeast than the approach used by EPA in their 2023 EN modeling platform. As ERTAC EGU is developed in collaboration between regional and state air planning agencies, it includes algorithms and data that have been reviewed by many of the states impacted by interstate O_3 transport in the Eastern U.S.

The LADCO 2023 CAMx simulation relative to the EPA 2023 EN simulation is an example of an alternative power sector modeling flexibility. The only configuration difference between these simulations is in the EGU emissions used with CAMx to project future year air quality. This sensitivity is slightly confounded by differences in the EPA and LADCO computing platforms when directly comparing the runs. The computing system porting differences between the two runs is relatively small (see Section 5.1) compared to the differences introduced by changing the EGU emissions.

Figure 9 and Figure 10 illustrate the differences in 2023 MDA8 O_3 that result from changing the EGU projection methodology. As described in Section 5.2, the EPA simulation predicts higher O_3 in the Midwest, Northeast, Gulf Coast, and Pacific Coast states; the LADCO simulation predicts higher O_3 in the Four Corners region and Central Arkansas. Figure 24 and Figure 25 compare summer season MDA8 O_3 between the LADCO and EPA 2023 simulations for monitors in the AQS and CASTNET networks, respectively. The LADCO simulation (y-axis) predicts slightly lower O_3 concentrations across all sites (AQS NMB = -0.89%, CASTNET NMB = -0.4%).

Figure 26 and Figure 27 compare the EPA and LADCO 2023 DVFs for the Eastern US and the LADCO region, respectively. Table 7 shows the DVFs and DVCs for the nonattainment and maintenance monitors in the Eastern U.S. ***The LADCO simulation that used ERTAC EGU emissions projections forecasts lower DVFs than the EPA 2023 EN simulation. All six of the projected nonattainment monitors in the EPA simulation are forecasted by the LADCO simulation to be in attainment.*** The RRF plots in Figure 28 further show the regional O_3 reductions in the LADCO simulation relative to the EPA 2023 EN simulation. More yellow and blue colors, representing lower RRFs or greater reductions in future year O_3, are seen in the LADCO simulation through the Great Lakes, Mid-Atlantic, and Northeast regions.

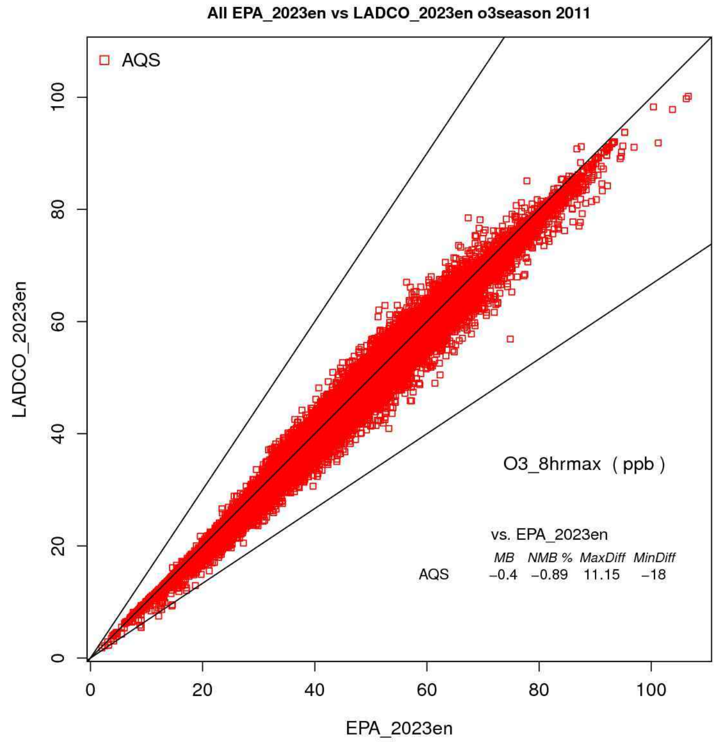

Figure 24. LADCO 2023 vs EPA 2023 summer season AQS MDA8 O_3

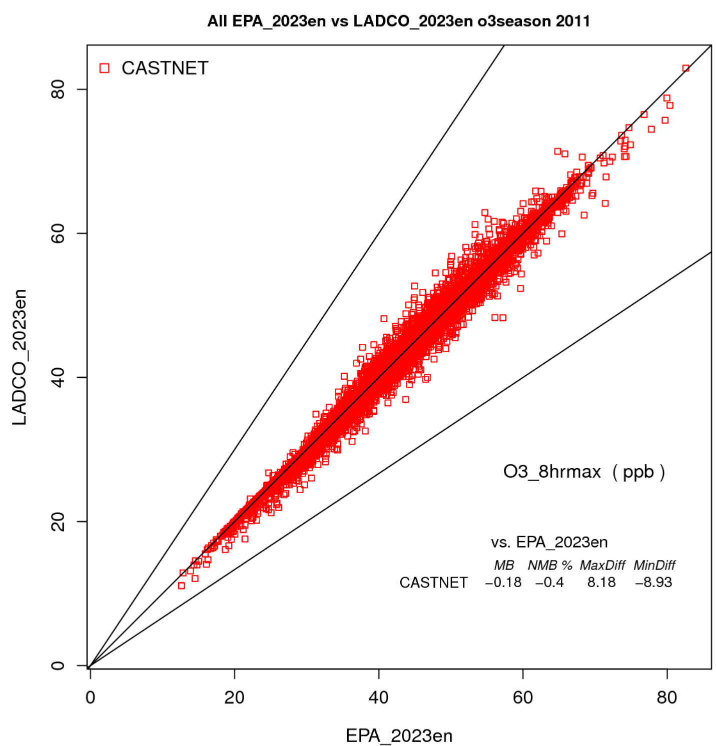

Figure 25. LADCO 2023 vs EPA 2023 summer season CASTNET MDA8 O_3

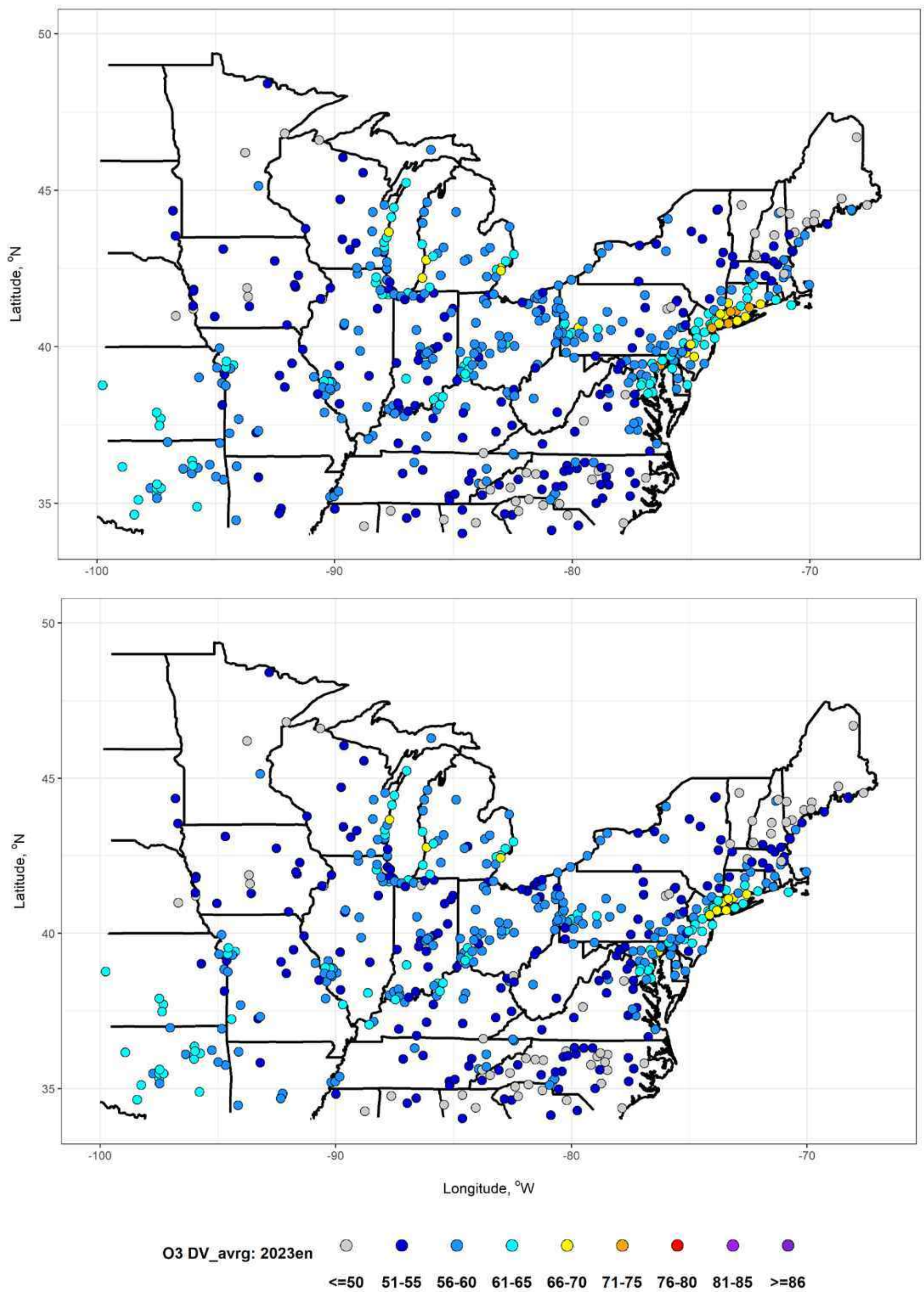

Figure 26. EPA (top) and LADCO (bottom) 2023 DVFs.

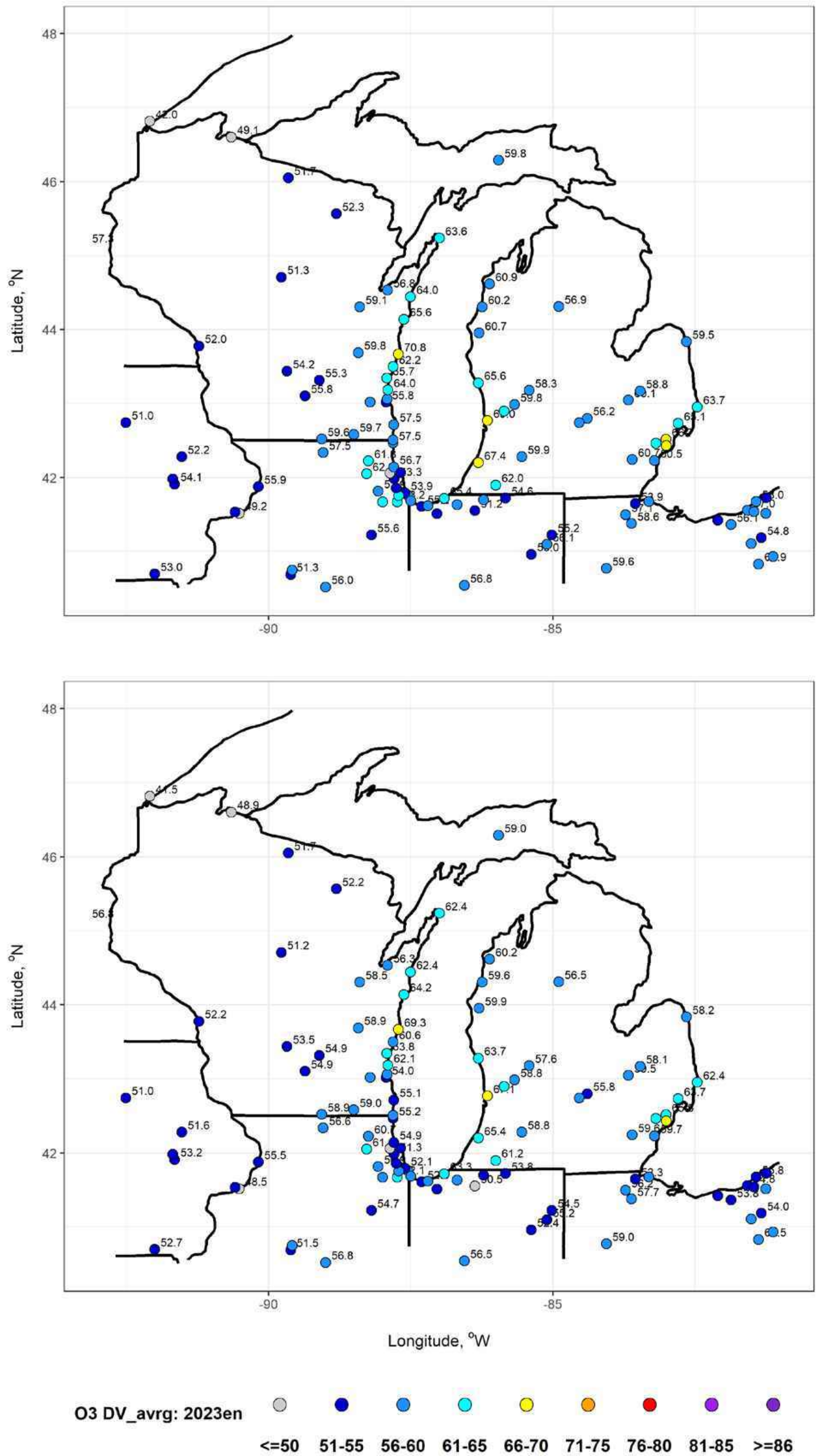

Figure 27. EPA (top) and LADCO (bottom) 2023 DVFs; LADCO zoom.

Table 7. LADCO and EPA 2023 O_3 design values at nonattainment and maintenance monitors in the Midwest and Northeast

AQS ID	County	ST	LADCO 3x3 avrg	LADCO 3x3 max	EPA 3x3 avrg	EPA 3x3 max	2009-2013 3x3 avrg	2009-2013 3x3 max
361030002	Suffolk	NY	69.8	**71.3**	**72.5**	**74.0**	83.3	85.0
90019003	Fairfield	CT	69.6	**72.4**	**72.7**	**75.6**	83.7	87.0
240251001	Harford	MD	69.4	**71.8**	**71.4**	**73.8**	90.0	93.0
551170006	Sheboygan	WI	69.3	**71.5**	70.8	**73.1**	84.3	87.0
360850067	Richmond	NY	69.1	70.6	**71.9**	**73.4**	81.3	83.0
90099002	New Haven	CT	67.9	70.5	**71.2**	**73.9**	85.7	89.0
90013007	Fairfield	CT	67.8	**71.6**	**71.2**	**75.2**	84.3	89.0
261630019	Wayne	MI	67.7	69.7	69.0	**71.0**	78.7	81.0
360810124	Queens	NY	67.5	69.2	70.1	**71.9**	70.0	71.0
90010017	Fairfield	CT	67.2	69.4	69.8	**72.1**	78.0	80.0
260050003	Allegan	MI	67.1	69.8	69.0	**71.8**	80.3	83.0
550790085	Milwaukee	WI	62.1	65.1	64.0	67.0	78.3	82.0

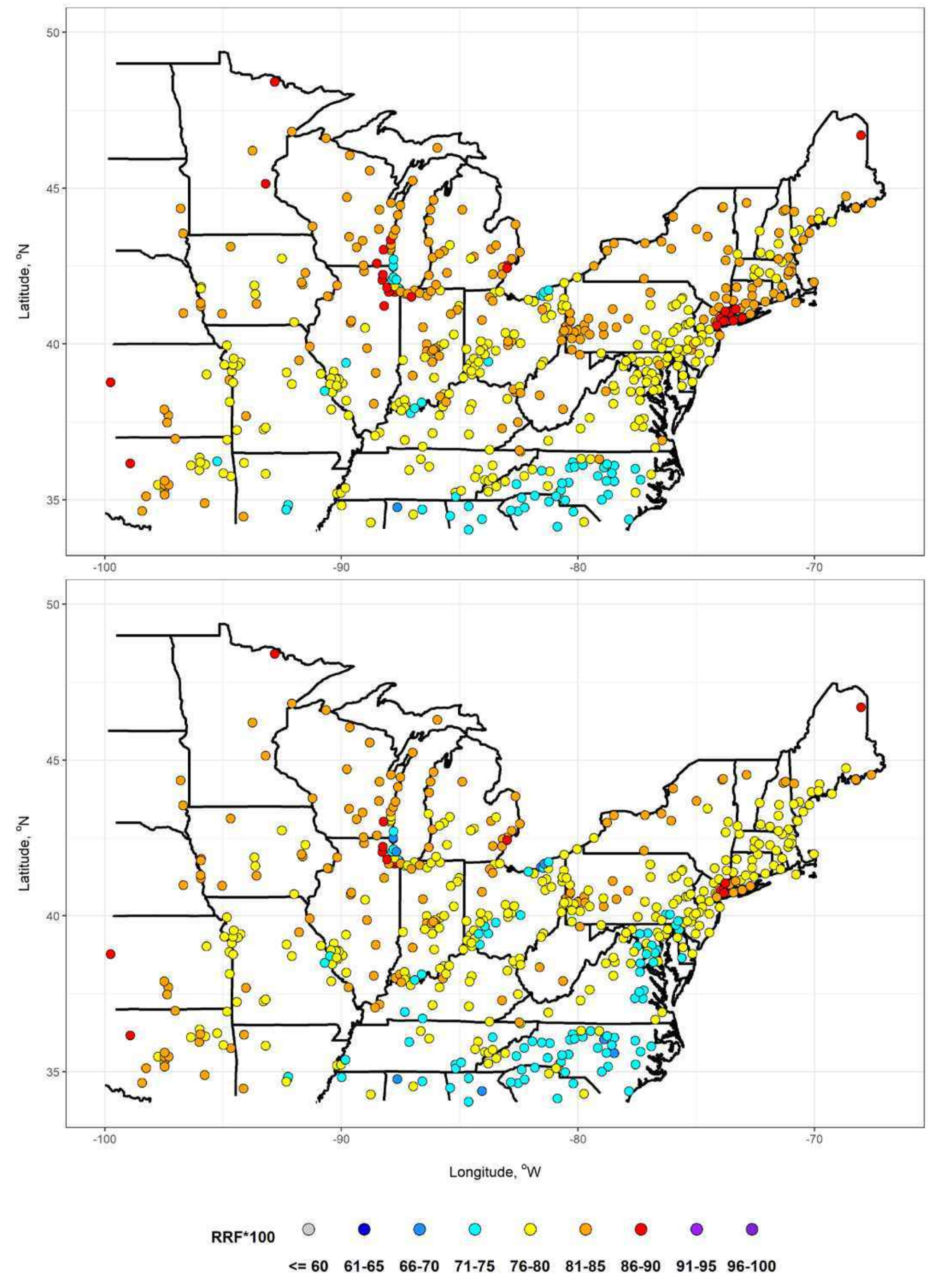

Figure 28. EPA (top) and LADCO (bottom) 2023 RRFs.

5.4.2 Impacts of Water Cells on Design Values

Confidence in the ability of photochemical models to accurately estimate O_3 over water is a persistent concern with the use of the models for air quality planning. This concern recently prompted measurement campaigns in the Eastern U.S. to address the issue (see Lake Michigan Ozone Study and Long Island Sound Tropospheric Ozone Study). The meteorology and chemistry processes in model grid cells that are dominated by water (> 50% landuse area) are a challenge to simulate because the conventional technical formulations of the models were not optimized for water cells. Even with the introduction of new algorithms to simulate the dynamical and chemical features of water cells, a lack of over-water observations hinders our ability to verify the accuracy of the models in simulating these conditions. In consideration that the models may not perform well in simulating water cells, EPA and others have presented alterative DVF calculation approaches that exclude water cells. Although not explicitly listed in Attachment A of the EPA's March 2018 memo on O_3 Transport Modeling as a flexibility to consider in developing a Good Neighbor SIP, the EPA used the exclusion of water cells in their own DVF calculations (US EPA, 2017a; US EPA, 2018). EPA implicitly endorses the exclusion of water cells when calculating DVFs in their most recent technical guidance for Good Neighbor SIPs (US EPA, 2018).

Exercising this flexibility does not require additional CAMx simulations. It is implemented through a postprocessing sequence per EPA (2018) in which model grid cells that are dominated by water (> 50% landuse area) are removed from the 3x3 matrix in the RRF and DVF calculation. One important modification to this process is to override the exclusion condition for cells that contain monitors; in other words, grid cells that contain monitors will be included in the 3x3 matrix regardless of the amount of water coverage in the cell. For the results presented here, LADCO used EPA postprocessing utilities and scripts that were developed to support their March 2018 memo.

Figure 29, Figure 30, and Table 8 present the impacts of excluding water cells in the DVF calculations for the LADCO and EPA 2023 simulations. Figure 29 and Figure 30 compare the water/no-water DVFs and RRFs for the LADCO simulation, respectively. ***In general, including water cells in the attainment test calculation results in lower DVFs for the lakeshore monitors in the LADCO region.*** A few key downwind monitors (Harford, MD; Richmond, NY; New Haven, CT) have higher DVFs when water cells are included in the calculation.

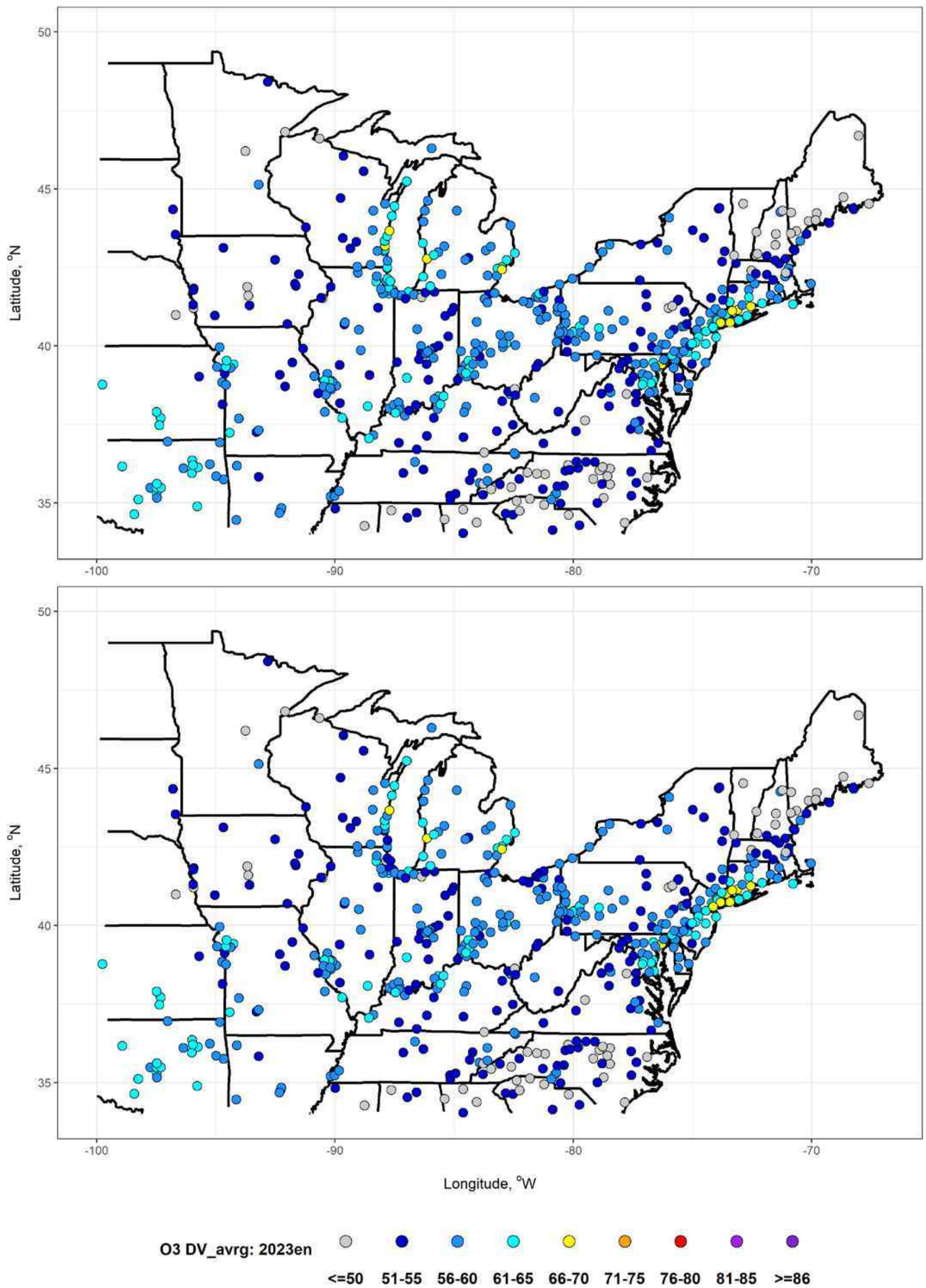

Figure 29. Ozone DVFs calculated with water cells excluded (top) and included (bottom) for the LADCO 2023 CAMx simulation.

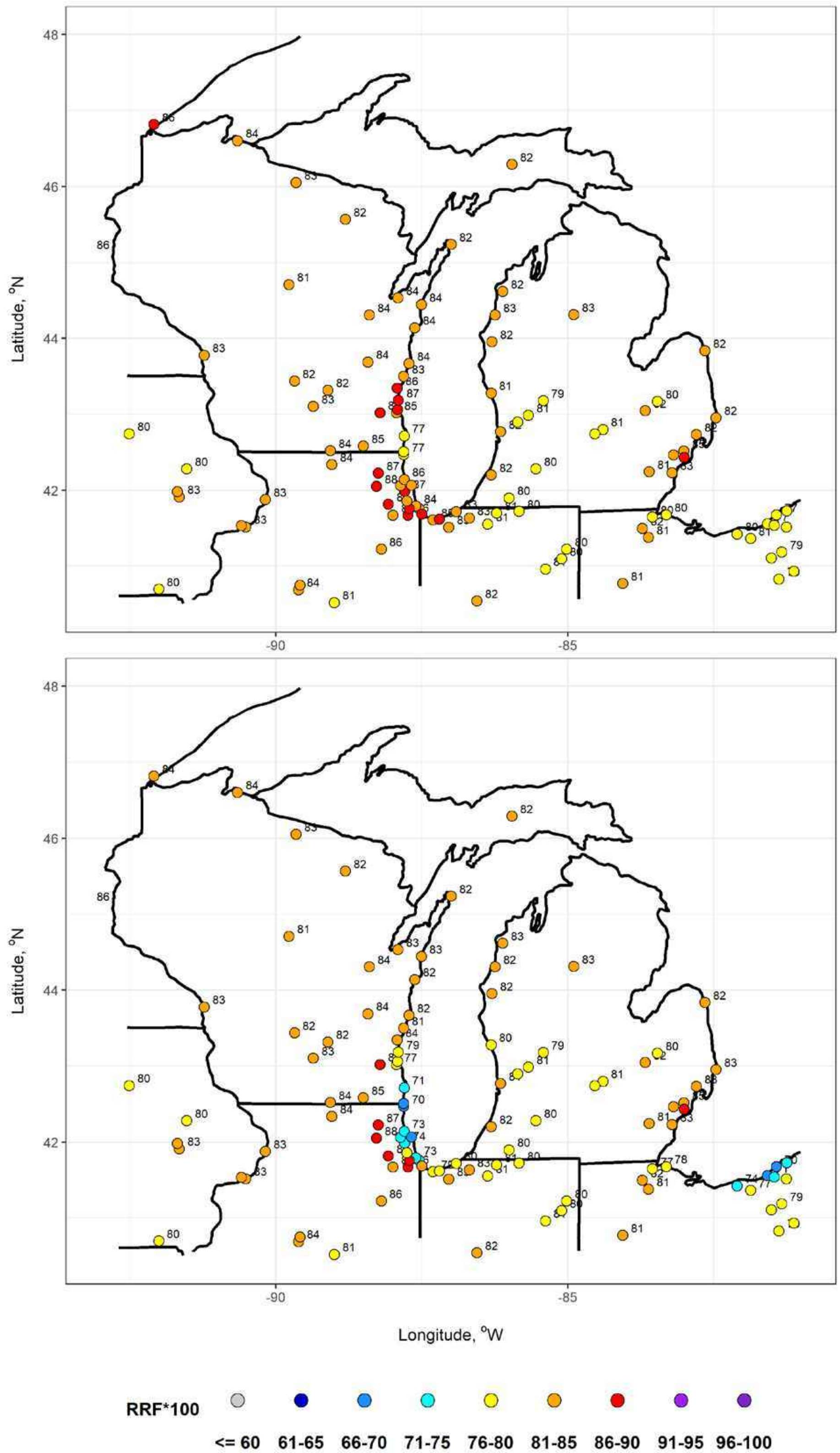

Figure 30. Ozone RRFs calculated with water cells excluded (top) and included (bottom) for the LADCO 2023 CAMx simulation.

Table 8. LADCO and EPA 2023 O_3 DVFs with and without water cells

AQS ID	County, ST	LADCO Water		LADCO No Water		EPA Water		EPA No Water	
		3x3 avrg	3x3 max	3x3 avrg	3x3 max	3x3 avrg	3x3 max	3x3 avrg	3x3 max
361030002	Suffolk, NY	69.8	**71.3**	70.8	**72.2**	**72.5**	**74.0**	**74.0**	**75.5**
90019003	Fairfield, CT	69.6	**72.4**	70.1	**72.9**	**72.7**	**75.6**	**73.0**	**75.9**
240251001	Harford, MD	69.4	**71.8**	69.2	**71.5**	**71.4**	**73.8**	70.9	**73.3**
551170006	Sheboygan, WI	69.3	**71.5**	70.9	**73.2**	70.8	**73.1**	**72.8**	**75.1**
360850067	Richmond, NY	69.1	70.6	64.5	65.8	**71.9**	**73.4**	67.1	68.5
90099002	New Haven, CT	67.9	70.5	66.8	69.4	**71.2**	**73.9**	69.9	**72.6**
90013007	Fairfield, CT	67.8	**71.6**	68.1	**71.9**	**71.2**	**75.2**	**71.0**	**75.0**
261630019	Wayne, MI	67.7	69.7	67.7	69.7	69.0	**71.0**	69.0	**71.0**
360810124	Queens, NY	67.5	69.2	67.1	68.8	70.1	**71.9**	70.2	**72.0**
90010017	Fairfield, CT	67.2	69.4	65.8	68.0	69.8	**72.1**	68.9	**71.2**
260050003	Allegan, MI	67.1	69.8	67.4	70.1	69.0	**71.8**	69.0	**71.7**
550790085	Milwaukee, WI	62.1	65.1	68.0	71.2	64.0	67.0	69.7	73.0

5.4.3 Model Bias Filtering

Under the Step 1 flexibilities for Good Neighbor SIP analyses in the EPA March 2018 memo, EPA says that states may "[c]onsider removal of certain data from modeling analysis for the purposes of projecting design values and calculating the contribution metric where data removal is based on model performance and technical analyses support the exclusion." Per this flexibility, for the monitors analyzed in this document LADCO filtered the days used for calculating RRFs and DVFs with an absolute bias threshold of 15%. Instead of calculating RRFs at each monitor from the 10 highest concentration MDA8 modeled days in the base year, we used the 10 highest days with absolute biases <= 15%. We applied the bias filtering to the attainment test calculations that include water cells.

Table 9 and Table 10 compare the LADCO and EPA O_3 DVFs and RRFs with and without bias filtering. The change in the LADCO average DVFs from applying the bias filtering ranged from a 2.2% decrease for the Fairfield, CT (AIRS ID: 90019003) monitor to a 4.8% increase for the Milwaukee, WI (AIRS ID: 550790085) monitor. Although the percentage differences from applying the bias filters are not exactly the same between the two CAMx simulations, the impacts to the EPA average DVFs was proportional to the LADCO DVF calculations. In other words, the bias filtering causes the DVFs to change in the same direction for both simulations. The bias filtering also had comparable impacts on both the average and maximum DVFs. ***Applying the bias filter increases the DVFs at the Sheboygan, WI; Allegan, MI, and Milwaukee, WI monitors; the DVF at the Wayne, MI monitor decreases with the application of the bias filter.*** It should be noted that the bias filtering has more of an impact on the DVFs when water cells are included in the attainment test calculations (these results are not shown here).

Table 9. LADCO 2023 O_3 DVFs and RRFs with and without bias filtering

AQS ID	County, ST	LADCO Water			Bias < 15%		
		3x3 avrg	3x3 max	RRF	3x3 avrg	3x3 max	RRF
361030002	Suffolk, NY	69.8	71.3	0.8390	70.5	71.9	0.8465
90019003	Fairfield, CT	69.6	72.4	0.8327	68.1	70.8	0.8139
240251001	Harford, MD	69.4	71.8	0.7721	69.7	72.1	0.7755
551170006	Sheboygan, WI	69.3	71.5	0.8224	70.7	73.0	0.8391
360850067	Richmond, NY	69.1	70.6	0.8510	69.6	71.1	0.8573
90099002	New Haven, CT	67.9	70.5				
90013007	Fairfield, CT	67.8	71.6	0.8048	67.1	70.8	0.7965
261630019	Wayne, MI	67.7	69.7	0.8613	66.4	68.3	0.8443
360810124	Queens, NY	67.5	69.2	0.8658	66.5	68.2	0.8530
90010017	Fairfield, CT	67.2	69.4	0.8371	67.2	69.5	0.8381
260050003	Allegan, MI	67.1	69.8	0.8117	67.9	70.6	0.8219
550790085	Milwaukee, WI	62.1	65.1	0.7943	65.1	68.2	0.8325

Table 10. EPA 2023 O_3 DVFs and RRFs with and without bias filtering

AQS ID	County, ST	EPA Water			Bias < 15%		
		3x3 avrg	3x3 max	RRF	3x3 avrg	3x3 max	RRF
361030002	Suffolk, NY	72.5	74.0	0.8710	73.2	74.7	0.8795
90019003	Fairfield, CT	72.7	75.6	0.8690	70.7	73.5	0.8456
240251001	Harford, MD	71.4	73.8	0.7939	71.7	74.1	0.7968
551170006	Sheboygan, WI	70.8	73.1	0.8409	72.9	75.2	0.8651
360850067	Richmond, NY	71.9	73.4	0.8850	73.1	74.6	0.8992
90099002	New Haven, CT	71.2	73.9				
90013007	Fairfield, CT	71.2	75.2	0.8451	69.9	73.8	0.8293
261630019	Wayne, MI	69.0	71.0	0.8768	67.6	69.6	0.8593
360810124	Queens, NY	70.1	71.9	0.8998	69.1	70.8	0.8860
90010017	Fairfield, CT	69.8	72.1	0.8697	69.5	71.8	0.8657
260050003	Allegan, MI	69.0	71.8	0.8349	69.3	72.1	0.8388
550790085	Milwaukee, WI	64.0	67.0	0.8179	68.1	71.4	0.8710

6 Significant Findings

References

Cross State Air Pollution Rule (CSAPR), 76 Fed. Reg. § 48,208 (final rule Aug 8, 2011)(to be codified at 40 C.F.R. pts. 51, 52, 72, 78, 97).

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Table 11. APCA Source Regions

FIPS	APCA Region ID	NAME
N/A	1	Biogenic
17	2	Illinois
55	3	Wisconsin
18	4	Indiana
39	5	Ohio
26	6	Michigan
27	7	Minnesota
19	8	Iowa
29	9	Missouri
5	10	Arkansas
22	11	Louisiana
48	12	Texas
40	13	Oklahoma
20	14	Kansas
31	15	Nebraska
Multiple	16	Maine, New Hampshire, Vermont, Massachusetts, Rhode Island
9	17	Connecticut
36	18	New York
34	19	New Jersey
42	20	Pennsylvania
10	21	Delaware
24	22	Maryland
	23	Washington DC
54	24	West Virginia
51	25	Virginia
Multiple	26	North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Florida
21	27	Kentucky
Multiple	28	Arizona, Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota, Idaho,

FIPS	APCA Region ID	NAME
		Washington, Oregon, California, Nevada
N/A	29	Canada/Mexico
N/A	30	Offshore
N/A	31	Tribal
N/A	32	Fire

MINNESOTA POLLUTION CONTROL AGENCY

Attachment 2:

Documentation of ERTAC EGU CONUS Versions 2.7 Reference and CSAPR Update Compliant Scenario

Lake Michigan Air Directors Consortium (LADCO) | 17 pages | September 2017

Documentation of ERTAC EGU CONUS Versions 2.7 Reference and CSAPR Update Compliant Scenario

9/23/2017

ERTAC EGU Committee

Contents

Introduction

The ERTAC Electricity Generating Unit (EGU) Committee develops reference runs for the continental United States (CONUS). CONUS 2.7 is based on 2011 base year continuous emission monitoring (CEM) data and growth factors from the AEO2017 projection that does not include the Clean Power Plan (US Energy Information Administration January 2017). Input files to version 2.7, were developed using input received by June 2017 from a significant outreach effort to states and stakeholders. Final V2.7 runs were done by VA DEQ and OTC in September 2017. The contact person for questions about these run files is Doris McLeod (804-698-4197) for all runs except 2023. For 2023, the contact person is Joseph Jakuta (jjakuta@otcair.org). CONUS 2.7 includes both a reference run and a Cross State Air Pollution Update (CSAPR Update) Rule (81 FR 74504) compliant scenario. The reference run includes only unit change information provided by states. The CSAPR Update compliant run include additional unit adjustments, described further in this text, agreed upon by the ERTAC EGU committee to represent the EGU sector operating in compliance with the CSAPR Update rule. Projections for reference case runs have been prepared for years 2017, 2018, 2019, 2020, 2023, 2025, and 2030. Projections for CSAPR Update compliant scenario have been prepared for years 2020, 2023, 2025, 2028, and 2030. The CSAPR Update compliant files are described also as optimized runs. File names that pertain to the CSAPR Update compliant run include the "opt" identifier in file names.

The ERTAC EGU Committee maintains and distributes reference runs for the continental United States (CONUS), including the hourly input, output, summary, and documentation files for each run. These reference runs and the CSPR Update Compliant Scenario and complete documentation of the ERTAC EGU Tool is located on the MARAMA web site located here:

http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

ERTAC Input Files

The ERTAC EGU Tool input files are built by the ERTAC leadership committee from a wide variety of existing data. These input files are subject to periodic quality assurance and updating by state agency staff. Agencies provide information on new units and controls, fuel switches, shutdowns and other unit-specific changes. In addition, the ERTAC EGU growth committee prepares updates to the growth factors when new versions of the Energy Information Agency (EIA) Annual Energy Outlook (AEO) become available. Periodic updates of these input files drive creation of new run versions. The ERTAC EGU tool projects fossil fuel fired units that report emissions to USEPA Clean Air Markets Division (CAMD) and serve a generator of at least 25 MW (there are some exemptions in the North East where units are sized less than 25 MW).

A key data source are the hourly reports of generation and emissions collected by CEM and electronically reported to CAMD by facilities for the base year, in this case 2011. Base year SO_2 and NO_X emission rates (lb/mmbtu) are calculated from this data. Future emission rates are developed from base year rates adjusted to account for state knowledge of expected emission controls, fuel switches, retirements, and new units.

The primary sources of expected future change in generation is the Energy Information Agency (EIA) annual projection of future generation and the National Energy Reliability Corporation (NERC) projection of peak generation rates. This information is available by region and fuel type. Where states have local projections these are preferred over national sources. Future generation by unit is estimated by merging these national, regional and state growth files with state knowledge of unit level changes. Hourly future emissions of NO_X and SO_2 are calculated by multiplying hourly projected future heat input by future emission rates.

ERTAC EGU Tool input files are as follows:

- **Base Year Hourly CEM data** – This comma separated file contains hourly unit level generation and emissions data extracted from EPA's CAMD database. In unit-specific situations where base year hourly data needs to be modified, users provide a non-CAMD hourly file, which may be used to adjust or add data to the base year hourly CEM file.

- **Unit Availability File (UAF)** – This tabular file contains descriptions of each generating unit derived from a variety of sources, including the CAMD NEEDS database, state input, EIA Form 860, and NERC data. Each row in the table represents a single generating unit. This file is maintained and updated by the ERTAC committee and provides information on changes to specific units from the base to the future year. For example, the UAF captures actual or planned changes to utilization fractions, unit efficiency, capacity, or fuels. State/Local/Tribal (S/L/T) agencies also add information on actual and planned new units and shutdowns.

- **Control File** – This tabular file contains known future unit specific changes to SO_2 or NO_X emission rates (in terms of lbs/mmBtu) and/or control efficiencies (for example, addition of a scrubber or selective catalytic reduction system). This information is provided by S/L/T agency staff. This file also provides emission rates for units that did not operate in the base year.

- **Seasonal Controls File** – This optional tabular file may be used by S/L/T agencies to enter seasonal or periodic future year emissions rates for specific units for use in future year runs. This file may be used in addition to, or as an alternative to, the Control File.

- **Input Variables File** – This tabular file specifies values for a number of variables used in a particular projection run.

    - **Regions and Fuel Characteristics** are not hardwired into the model. Rather, the regions and their characteristics are specified in the Input Variables File. This file allows the S/L/T agencies to specify variables such as the size, fuel type and location for new units. In addition, the regional scheme and fuel types are specified in this file.

    - **Default New Unit Emission Rates.** Percentile of best performing existing unit emission rates for use in new units. Default is 90th percentile.

    - **New Unit Hourly Profile Characteristics.** For new planned units and generation deficit units (GDUs), users may specify in this file the percentile ranking of the existing unit (operated in the base year) used to create a representative future profile of activity for new units and GDUs.

- **Growth Factor File** – This tabular file contains the annual, nonpeak and peak electrical generation growth factors delineated by geographic region and generating unit type used in a particular run.

    - **Peak Growth and Transition Hours**. The number of peak and transition hours, differentiated by fuel and region, are assigned in the Growth Factor File.

- **Demand Transfer File** – This optional file allows users to transfer power, on an hourly basis, from one region/fuel-unit type to another. It also allows transfer to or from other, non-fossil fuel fired systems such as nuclear and renewables.

Growth factors

Generation for future years by fuel type are based on growth rates which are differentiated by annual, nonpeak, and peak rates.

Annual growth rates are developed by the ERTAC EGU Growth subcommittee from the EIA Annual Energy Outlook (AEO) and NERC projections. In certain cases, S/L/T agencies have developed more refined region specific growth factors which are then used to replace the EIA/NERC factors developed from other information sources, along with supporting documentation for those growth rates. EIA annual average regional growth factors are calculated by dividing AEO future projected generation by base year generation.

Peak growth rates are derived by determining relative peak growth from NERC Electricity Supply & Demand (ES&D) data and applying it to the annual growth rates. The derived relative peak growth rates are not delineated by fuel so the ratio of peak to nonpeak growth rates for each fuel within a single region is constant.

Nonpeak growth rates are calculated within the ERTAC EGU Tool using annual and peak growth rates. Annual average regional growth rates are adjusted to account for the peak hours.

Peak and nonpeak growth is assigned to every hour by ordering all hours of the year by base year utilization. The peak growth factor is assigned by fuel to a limited number of hours with the highest utilization in the base year. Growth is then transitioned gradually to non-peak growth rate. The number of peak and transition hours are differentiated by fuel and region and are assigned in the Input Variables File. Figure 1 shows graphically the relationship between annual, peak and nonpeak growth rates.

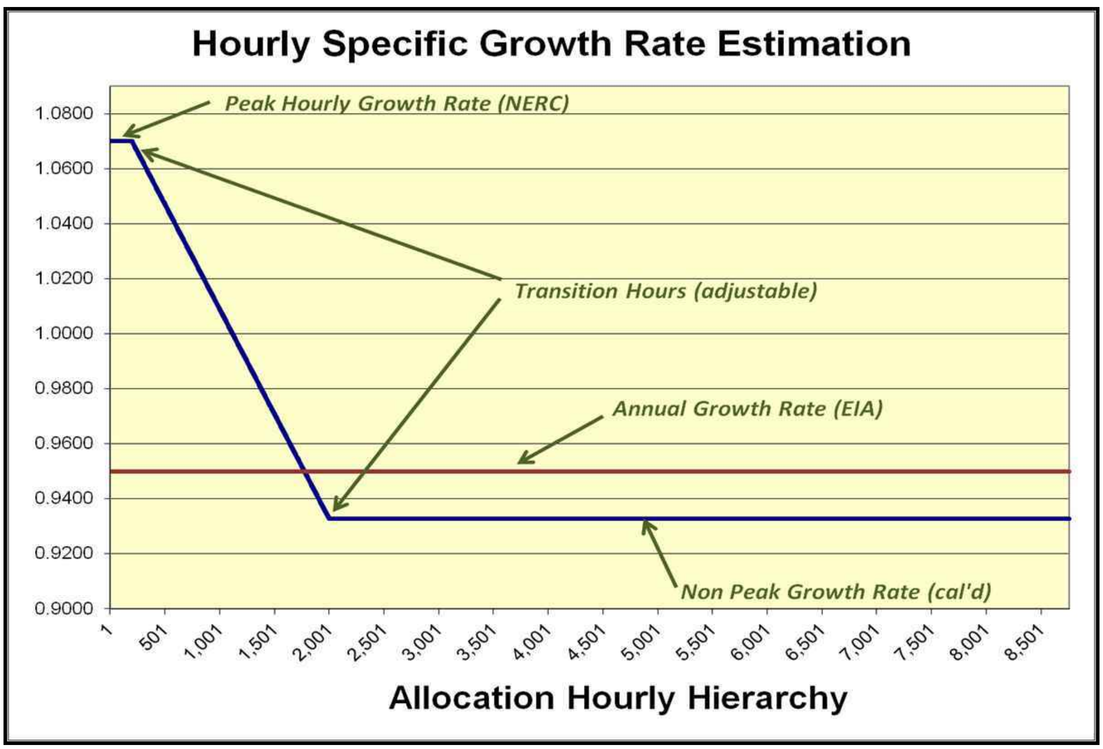

Figure 1. Relationship between the annual, peak, and nonpeak growth rates

Finally, fuel specific hourly regional growth factors are adjusted to account for activity from new units and shutdowns. The tool then applies the adjusted hourly growth factors to the base year hourly generation data to estimate hourly future generation. This generation is assigned to the units burning the specified fuel within the region. After generation is assigned, the tool confirms that unit capacity is not exceeded. If the available capacity is fully utilized new, generic units ("Generation Deficit Units") are created to carry demand that exceeds known unit capacity.

NO_X and SO_2 Emissions

For base year runs, actual CAMD data is averaged to calculate base year ozone season and non-ozone season emission rates.

For future year runs, calculated base year average emission rates for existing units are adjusted to account for new control equipment or other changes provided in the input files.

For new units, two approaches are employed. First, if a state provides new unit emission rates those are used directly. Where emission rates are not provided, these are estimated based on the 90th percentile best performing existing unit for that fuel type and region. The user may adjust this percentile within the input variables file. These rates are applied to each unit's future generation to calculate NO_X and SO_2 emissions.

Output

The ERTAC tool generates hourly generation and emissions for each unit included in the system. In addition, post processors create summary files to facilitate review of the results, as follows:

- Annual base and future year generation (MW-hrs), heat input (mmbtu), SO_2, NO_X emission (tons) and average emission rate (lbs/mmbtu)
- Ozone season base and future year generation and heat input, NO_X emission (tons) and average emission rate (lbs/mmbtu)

Post processors are also available to generate CO_2 estimates.

Geographic Regional System

Each EGU unit included in the model is assigned to a geographic region and fuel type bin in the Unit Availability File. The geographic regional system provided in Figure 2 is used in versions 2.7 reference and CSAPR Update compliant runs is the EIA Electricity Market Module (EMM) regional system. One adjustment that the EIA EMM system for the ERTAC EGU system is that SPNO and SPSO have been combined into a single region.

Because the EIA EMM and NERC regions are not identical, adjustment is required to align these regional systems to develop annual and peak growth rates. To match EIA and NERC, a "best fit" NERC regional growth factor is assigned to each EMM region. In the simplest case, where a clear match between EIA and NERC regional schemes exists, for example NPCC-New England, the NERC relative peak growth rate is assigned to the corresponding EMM region. In more complicated cases, where multiple EMM regions corresponded to a single NERC region, or where regions were organized along substantially different geographic boundaries, the NERC ES&D data was aggregated and averaged to generate a relative peak growth factor for the (usually larger) corresponding NERC region and was applied to the corresponding ERTAC region (which closely resemble the EMM regions). As an example, the EIA SRVC, RFCW, and RFCE regions corresponds to two NERC regions, PJM and SERC East. In this case, the relative peak growth factors were derived from PJM and SERC East and applied to SRVC, RFCW, and RFCE ERTAC regions.

Within each region, individual generation units are further delineated into five unit types as follows:

- Coal;
- Oil;
- Natural Gas – Combined Cycle;
- Natural Gas – Single Cycle;
- Natural Gas – Boiler gas.

Figure 2: Regional boundaries for coal generation, CONUSv2.7

Figure 4: EMM to NERC Crosswalk – ERTAC EGU V2.7

EMM Fuel Region #	Fuel	EMM Region Name	ERTAC Regional Code	Single "Best-Fit" NERC Subregion Peak Growth Code
1	Coal, NG, Oil	Texas Regional Entity (ERCT)	ERCT	ERCOT
2	Coal, NG, Oil	Florida Reliability Coordinating Council (FRCC)	FRCC	FRCC
3	Coal, NG, Oil	Midwest Reliablity Council / East (MROE)	MROE	MISO / SPP / SERC-N
4	Coal, NG, Oil	Midwest Reliablity Council / West (MROW)	MROW	MISO / SPP / SERC
5	Coal, NG, Oil	Northeast Power Coordinating Council / Northeast (NEWE)	NEWE	NPCC - NE
6	Coal, NG, Oil	Northeast Power Coordinating Council / NYC Westchester (NYCW)	NYCW	NPCC - NY
7	Coal, NG, Oil	Upstate New York (NYUP)	NYUP	NPCC – NY
8	Coal, NG, Oil	Long Island (NYLI)	NYLI	NPCC - NY
9	Coal, NG, Oil	Reliability First Corporation / East (RFCE)	RFCE	PJM / SERC - E
10	Coal, NG, Oil	Reliability First Corporation / Michigan	RFCM	MISO / SPP / SERC
11	Coal, NG, Oil	Reliability First Corporation / West	RFCW	PJM / SERC - E
12	Coal, NG, Oil	SERC Reliability Corporation / Delta (SRDA)	SRDA	MISO / SPP / SERC
13	Coal, NG, Oil	SERC Reliability Corporation / Gateway (SRGW)	SRGW	MISO / SPP / SERC
14	Coal, NG, Oil	SERC Reliability Corporation / Southeastern (SRSE)	SRSE	SERC - SE
15	Coal, NG, Oil	SERC Reliability Corporation / Central (SRCE)	SRCE	MISO / SPP / SERC
16	Coal, NG, Oil	SERC Reliability Corporation / Virginia Carolina (SRVC)	SRVC	PJM / SERC - E
17+18	Coal, NG, Oil	SouthWest Power Pool / North (SPNO) + South (SPSO)	SPPR	MISO / SPP / SERC
19	Coal, NG, Oil	Western Electricity Coordinating Council / Southwest (AZNM)	AZNM	WECC-WECC-SWSG
20	Coal, NG, Oil	Western Electricity Coordinating Council / California (CAMX)	CAMX	WECC-CAMX US
21	Coal, NG, Oil	Western Electricity Coordinating Council / Northwest Power Pool Area (NWPP)	NWPP	WECC-NWPP US
22	Coal, NG, Oil	Western Electricity Coordinating Council / Rockies (RMPA)	RMPA	WECC-WECC-RMRG

DETAILS OF VERSION 2.7 REFERENCE AND CSAPR UPDATE COMPLIANT RUNS

ERTAC EGU v2.7 was built on improvements to prior runs and included updates to the UAF and control file from states received as of July. A summary of the inputs used to develop the ERTAC EGU v2.7 Reference and CSPAR Compliant runs for the continental United States are shown in Figures 5 and 6 respectively. Details of these changes may be found in the change log document. (ERTAC 2017a)

ERTAC EGU CODE 2.1 – BOTH V2.7 REFERENCE AND CSAPR UPDATE COMPLIANT SCENARIO

Version 2.7 was the first usage of the ERTAC EGU v2.1 code. V2.1 added a new functionality, including the ability to transfer of load between fuel types and regions. Use of this transfer functionality is described later in this document. (ERTAC 2017b)

REGIONAL BOUNDARIES GROWTH RATES– BOTH V2.7 REFERENCE AND CSAPR UPDATE COMPLIANT SCENARIO

AEO regions SPSO and SPNO were aggregated into a single region called SPPR for the coal fuel type only. - SPP operates as a single balancing authority and single wholesale market for the SPPR region. Hence growth in wholesale power production occurs within that single market construct. Application of differential growth rates by fuel type between SPPS and SPPN obscures that single market construct and can produce counter-intuitive fuel-specific emissions forecasts. Combining the individual net generation forecasts for a single fuel type allows for an accurate averaging of the growth rates into an integrated whole. The anticipated outcome will be more reflective of the generation efficiencies and relative fuel balance based on the application of a single wholesale market construct. Since there have been issues of predicted over-emissions in one or more of the states (most notably Oklahoma) when forecasting the two independent smaller regions within the ERTAC construct, the bigger regional footprint partially alleviates this specific problem due to the rebalanced loading for each fuel-unit type.

GROWTH RATES – BOTH V2.7 REFERENCE AND CSAPR UPDATE COMPLIANT SCENARIO

Growth factors used in both v2.7 reference and CSAPR Update compliant scenario were developed based on AEO2017 No Clean Power Plan Case. Relative peak factors were derived from 2016 NERC Electricity Supply & Demand (ES&D). The file containing annual and peak growth factors was provided by Tom Shanley of the ERTAC EGU Growth committee and is named:

CONUSv2.7_AEO2017Ref_noCPP_SPPR_T2017_2030_ertac_growth_rates_7-17-2017.xlsx

These growth factors and default growth curve parameters were used with the following exceptions:

- **SRVC**[1] replaced AEO growth rates and growth curve shape with values based on regional knowledge for combined cycle, Boiler gas and simple cycle fuel bins. The updated local values were used for all future year projections. Development of the local values is described in a memo included as an appendix to this document. Specific changes include:
    - **Combined Cycle** peak to nonpeak growth transition points were set to 200 and 2000 to reflect the fairly large difference in average and peak growth rates (AGR and PGR).
    - **Boiler Gas and Simple Cycle** transition points were set to 100 and 1000 to reflect the large difference in AGR and PGR and ameliorate the Generation Deficit Units (GDU)
    - Any year not included in the SRVC memo was interpolated between SRVC information.

[1] updated using PGR/AGR information in email dated August 8, 2017, transmitted via email from Ming Xie of NC on August 9, 2017.

- **NYCW**[2] replaced AEO annual growth rates with values based on regional knowledge for all fuel bins. The updated local values were developed for 2020 and 2025 and interpolated[3] for use for all future year projections. Development of the local values is described in a memo included as an appendix to this document. Specific changes include: xxx
- **RFCE and RFCM** default growth curve transition points for the combined cycle fuel bin (CC) were replaced with 100 and 1000 to reflect the large growth and increased reliance on CC for base loaded operation in those regions.
- **SRGW** boiler gas peak growth rate for 2028 and 2030 was reduced to 0.98 so that the infinite GDU bug is not triggered. Annual growth rate was not affected.

ERTAC Demand Transfer– Both V2.7 Reference and CSAPR Update compliant Scenario

Demand transfer is a new concept made possible by use of the new v2.1 ERTAC EGU code. The concept is to transfer some demand for particular hours from one fuel bin to alleviate the generation of a GDU. Another use for a demand transfer is the case where a significant system change occurs which was not anticipated by the EIA in the AEO. The example in V2.7 is the retirement of a large nuclear power plant near New York City. This results in other fuel bins having to provide a large amount of generation that was unanticipated by the EIA in the AEO.

Transfers to prevent a coal fired GDU

- **NEWE** 300 MW-hrs was transferred from coal to combined cycle fuel bins in 861 deficit hours to prevent a coal fired GDU. There were 2000 MWs of unused CC capacity in NEWE. This transfer was done in every future year projected.
- **FRCC** Coal generation was transferred to the combined cycle fuel bin for certain hours to prevent a coal fired GDU. There was significant unused combined cycle capacity in FRCC.[4] This transfer was done in every future year projected. However, the amount of generation transferred, and the number of hours required varied by projection year as follows:
    - 2017 – No transfer required
    - 2018 – 2500 MW-hr coal to CC in 1259 deficit hours
    - 2019 – 1000 MW-hr coal to CC in 241 deficit hours
    - 2020 – 1300 MW-hr coal to CC in 444 deficit hours
    - 2023 – 600 MW-hr coal to CC in 59 deficit hours
    - 2025 – 600 MW-hr coal to CC in 90 deficit hours
    - 2028 – 1000 MW-hr coal to CC in 2040 deficit hours
    - 2030 – 1000 MW-hr coal to CC in 239 deficit hours

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[2] NY memo to MARAMA, dated 02-11-2016

[3] 2020 interpolated growth rates were approved by Ona Papageorgiou (NY) in an email dated 8/1/2017 from Ona to D. McLeod (VA)

[4] FL staff (Hastings Read) approved this approach in an email dated August 9, 2017, to D. McLeod, titled, "RE: FRCC updates for ERTAC CONUS2.7.

Transfers to ameliorate disappearing generation bug

- **RFCE** – In the 2023 and 2025 projection 300 MWh of coal generation in RFCE was transferred to Combined Cycle for each of 4 hours to ameliorate missing generation due to Utilization Fraction limitations on coal fired units. The table below shows the 4 hours. RFCE combined cycle has significant new capacity in 2023, and at least 1000 MW of unused capacity.

Figure XXX Coal Generation in RFCE Transferred to Combined Cycle to Ameliorate Missing Generation

	B	C	D	E	F	H	I	J	O	P	Q
	ertac_fuel_unit_type_bin	op_date	op_hour	calendar_hour	temporal_allocation_order	base_actual_generation	base_retired_generation	future_projected_generation	afygr	excess_generation_poo	
56	Coal	8/14/2011	14	5415	3471	11353	719.7	10048.17034	0.944971959	39.09317901	
57	Coal	8/14/2011	15	5416	3472	11678.6	718.5	10336.34829	0.943088866	128.5455752	
58	Coal	8/14/2011	16	5417	3473	11809.4	710.3	10452.1151	0.941708346	120.9371685	
59	Coal	8/14/2011	17	5418	3474	11830.9	696.9	10471.14405	0.940465606	82.56722527	
02											
03											

Transfers to address nuclear retirement

- **NYCW** - Indian Point nuclear power plant is scheduled to retire in 2021. John Barnes of NY (email dated 7/13/2017) advised that the nuclear transfers should be limited to years after 2021. (2021/2023/2028)

INPUT VARIABLES – BOTH V2.7 REFERENCE AND CSAPR UPDATE COMPLIANT SCENARIO

In SRVC the combined cycle percentile was set at 50th, coal to 70%, and simple cycle to 70th. This was based on region specific sizes, capacities, and characteristics.

NON-CAMD HOURLY FILE– BOTH V2.7 REFERENCE AND CSAPR UPDATE COMPLIANT SCENARIO

A small group of units with abnormal or missing base year hourly data are not assigned any generation by the tool in the future year. To correct this issue, these units are assigned one hour of reasonable, minimal activity in the non-CAMD hourly file to ensure processing. This improvement has negligible impact on base year data.

For ORIS 55178, CT-1 it appears in some hours this unit reported in KW-hr rather than MW-hr, so that certain hours had more than 20,000 MW-hr of production. To correct this issue, any reported load greater than 300 was changed to 300 to fix the 2011 anomalous data. This issue was not discovered in previous runs because the unit had been marked "non-EGU" in prior runs. The state updated this designation to "Full" in the 2.7 comment period, so that the anomalous data became apparent in trial runs[5].

MI and FL supplied gross load data for combined cycle units that did not report power produced from steam generation in the BY CAMD data.

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[5] See email from Adel Alsharafi (MO) dated 7/20/2017 to D. McLeod (VA)

Negative emissions and load values are replaced with zero.

Added a full year of data for:

- ORIS 8906 (Astoria) Unit IDs 30, 40, and 50—summed reheat and superheat reported data to create the pseudo units.
- ORIS 7839 (Ladysmith) Unit 5, which is equivalent to that reported in 2011 for 7838 (Remington) Unit 5. 7838, 5 does not exist. This is a 2011 CAMD reporting error.

Other similar anomalies were corrected and are documented in the Run Log.

Unit Availability File – Both V2.7 Reference and CSAPR Update compliant Scenario

Numerous detailed corrections and adjustments to these files were made for both v2.7 reference and CSAPR Update compliant runs based on S/L/T agency comments regarding the configuration, characteristics, and utilization estimates of their units. The file name for the final unit availability file is: 2011BASEUnit_Availability_v2.7_17noCPPSeptember 192017_code2_1.xls.

Boiler gas treatment: Many coal fired EGU units have recently announced conversions to firing as boiler gas units. This trend results in a future over-capacity of boiler gas capacity and shortfall of coal capacity compared with projected generation in many regions. These conversions have been left in the coal bin in several cases for two reasons:

- To address shortfall created in coal bin resulting in GDU formation to meet coal fired demand.
- To create a reasonable future year generation profile for the unit.

To address the shortfall the tool created coal fired Generation Deficit Units to meet the demand for coal fired generation. To ameliorate this imbalance, a decision was made to assign boiler gas characteristics, including emission rates to these units, but to leave them in the coal fuel bin. These units were assigned Utilization fractions typical of existing natural gas-fired boilers in their region. The following units were treated in this fashion:

- 6055, 2B1 (Big Cajun 2, LA) in SRDA. Coal to boiler gas conversion assigned a UF limitation of 0.5
- Xxxx We need a complete list of the units treated in this fashion.

Controls File/Seasonal Controls File - Application of Best Practices NO_X Control Rates to EGU Units With Existing Control Devices – V2.7 CSAPR Update compliant Scenario Only

ERTAC EGU V2.7 reference runs did not result in NO_X emissions that met the regulatory requirement to meet the 2017/2018 CSAPR Update budgets in FY 2023. Due to the conservative nature of SIP development and therefore inventory development, states may not always include lower ozone season NO_X rates in projections for units that have flexibility in how they run controls or combustion processes. To address this issue, the ERTAC committee developed the CSAPR Update scenario to reflect reasonable estimates of improved NO_X rates driven by the requirement to purchase allowances under CSAPR Update in future year projections to demonstrate a first-cut estimate of compliance with state level budgets, assurance levels, or regional budgets associated with the CSAPR Update rule addressing the 2008 ozone NAAQS. Files resulting from this approach to editing the control file and seasonal control file for each run are referred to as the “optimized files.” These changes are fully described in the control documentation file titled, "2011BASEControl File-v2.7_17noCPPSeptember 19,2017_code2_1.xls." The descriptions below are background and summaries of the control documentation file.

Development of optimized emission rates. - MD staff prepared an analysis of historical unit performance from 2005-2016 ozone seasons to determine historically best-observed NO_X emission rates for coal-fired units controlled by SCR or SNCR. (Vinciguerra et al 2017) This analysis was based on ERTAC 2.6 results. Based on this analysis it was estimated that 19 units fitted with SNCR could meet an average NO_X rate of 0.125 lbs/mmbtu in the ozone season. Also 141 units fitted with SCR were identified that could meet an average NO_X rate of 0.064 lbs/mmbtu in the ozone season. These average values were selected to represent optimized NO_X rates during the ozone season in the absence of a state-provided optimized NO_X rate. These values may be further updated in later runs to reflect rates from unit-specific analyses.[6] Additionally, OK staff prepared an analysis of ozone season NO_X rates for units within OK not equipped with post-combustion controls but that have reduced NO_X emissions in 2016 based on CAMD data.[7]

Units for which the optimized control rate were applied - To determine which units would receive optimized NO_X rates, Maryland developed a list of coal-fired EGUs within CSAPR states equipped with SCR or SNCR, and matched this list to the ERTAC 2.7 2023 results. The optimized NO_X rates were applied to SNCR units with a 2023 ozone season NO_X emission rate > 0.125 lbs/mmbtu and SCR units with a 2023 ozone season NO_X rate > 0.064 lbs/mmbtu unless the state already provided an ozone season controlled NO_X rate in the seasonal control file. This resulted in optimized OS rates for 163 units – 124 SCR and 39 SNCR units.

Oklahoma Units – Oklahoma submitted optimized ozone season NO_X rates for the CSAPR Update compliant run for the following additional units not included in Maryland's analysis. These rates are based on 2016 ozone season NO_X data as reported by the Oklahoma units to CAMD. For all units except 2952 Unit 6, the non ozone season rates were based on submitted data in the documentation controls file. For 2952, Unit 6, which had no submitted data, the non-ozone season rates were those supplied by the tool as the non-ozone season average in 2011.

Optimized control emission rates were only applied in the ozone season - The optimized rates were included in the seasonal controls files and applied from May 1 through Sept 30 each year, beginning in 2017. In other periods of the year emission factors were equivalent to the 2011 data for the non-ozone season unless states had provided controlled NO_X rates as inputs. Where states provided a future year controlled NO_X rate that controlled rate was used for the non-ozone season. State provided annual NO_X control information for optimized units was removed from the annual control file to ensure that the ERTAC EGU tool would correctly select the NO_X rate supplied in the optimized seasonal controls file. However, state comments concerning annual controls were preserved in the non-ozone seasonal control file records. The optimized controls file and seasonal controls file can be used for years 2020 and beyond with no further modifications to the files.

- **Controls file:**
  Based on 2011BASEControl File-v2.7_17noCPPSeptember 192017_code2_1.xls.

[6] Email dated 7/12/2017 from H. Ashenafi-MD to D. McLeod-VA contained the updated rates for the various ORIS code/Unit ID combinations.
[7] Email dated 8/3/2017 from T. Richardson-OK to D. McLeod-VA contained the updated rates for the various ORIS code/Unit ID combinations.

- **Seasonal Controls File:**
  Based on 2011BASEControl File-v2.7_17noCPPSeptember 1922017_code2_1.xls.
  The following items are documented in the controls file but are also worthy of explanation here:
  - North Carolina submitted a large number of new seasonal control records. For units with a pollutant in the seasonal controls file, those line items were deleted from the controls file. [8]

Figure XXX New Oklahoma Emission Rates based on 2016 CAMD

ORIS	Unit ID	Facility	State	ERTAC Region	Fuel/Unit Type Bin	Previously Submitted or Calculated OS NOx Rate, (lbs/mmbut)	Calc. 2016 CAMD OS NOx Rate (lb/MMBtu)
165	2	Grand River Dam Authority	OK	SPPR	Coal	0.1600	0.1461
2952	6	Muskogee	OK	SPPR	Coal	0.3391	0.2813
2956	1	Seminole (2956)	OK	SPPR	boiler gas	0.2030	0.1061
2956	2	Seminole (2956)	OK	SPPR	boiler gas	0.2120	0.0954
2963	3313	Northeastern	OK	SPPR	Coal	0.1500	0.1317
10671	1A	AES Shady Point	OK	SPPR	Coal	0.1225	0.0712
10671	1B	AES Shady Point	OK	SPPR	coal	0.1245	0.0716
10671	2A	AES Shady Point	OK	SPPR	coal	0.1262	0.0669
10671	2B	AES Shady Point	OK	SPPR	coal	0.1268	0.0662
50558	CC01	Oklahoma Cogeneration LLC	OK	SPPR	combined cycle gas	0.2000	0.1222

[8] See Ming Xie's email from NCDENR, dated 5/26/2017.

Prior Runs

Prior reference runs files and documentation using 2011 base year data are as follows:

v2.6 – Run in March, 2017, using input files current as of January 2017, and run by VA DEQ, IN DEP, and OTC in March 2017. Significant change in this run is that boiler gas units in many states, including PA were left in the coal bin and more seasonal controls were added, including MD. Growth factors are based on AEO2015 High Oil and Gas Scenario.

v2.5L2 - Run in August, 2016, using input files current as of August 2016, and run by VA DEQ. Growth factors are based on AEO2015 High Oil and Gas Scenario.

v2.4 – Run in August, 2015, using input files current as of July 2015, and run by VA DEQ. As occurred with v2.3, growth factors are based on AEO2014

v2.3 – Run in October 2014. This run included major updates to the UAF and Control files received as of August 24, 2014. This is the first use of growth rates from AEO2014.

v2.2 – Run in June 2014. Same as v2.1. This run included major updates to the UAF and Control files received as of March 31, 2014. This is the first use of the new code 1.01. Growth rates were from AEO2013.

v2.1L1 – Run in April 2014. Same as 2.1 except this run included updates from Midwest to UAF and control file for Indiana, Illinois, Wisconsin, Michigan and Ohio primarily for coal fired units received dated March 3, 2014.

v2.1 – Run in March 2014. This run included updates to the UAF and control file from several states. UAF updated with adequate data to calculate an ERTAC heat rate. Negative values in CAMD replaced with zero. An adjustment to implement zero growth for the Boiler gas was included. Combustion turbines and combined cycle units were adjusted in the 2.1 factors to account for the boiler-gas generation.

v2.0 – Run in January 2014. This run was the first using base year 2011. In addition, the Midwest states provided updates to the UAF and control files. These updates were completed by the Northeast in prior runs.

Figure 3 and summarize the inputs to v2.7 Reference and CSAPR Update compliant runs, respectively.

Figure 3: Inputs to ERTAC EGU v2.7 Projection Runs

ERTAC File Name	Description	Run Notes
OVERVIEW	Version 2.7	Run by VA DEQ - Doris McLeod , OTC-Joseph Jakuta in Aug-Sep 2017
	Code: 2.1	New code, with new ertac_demand_transfer feature. Also, used a file converter for the new code to update to v2.1 format the UAF and input variables. This set of runs will be the only set using the file converter. Next runs will start with the v2 formats.
	Base Year: 2011	
	Future Years: 2017, 2018, 2019, 2020, 2023, 2025, 2030 (in nomenclature of files, XX denotes year, example 17 = 2017)	Note that years 2020-2030 have both ref and opt runs. Ref indicates all inputs are based on state supplied data. Opt indicates that state supplied data was augmented with MD optimization control strategy, and OK supplied unit-specific data solely for optimization runs.
camd_hourly_base.csv	Hourly CAMD CEM data	Same for all years.
ertac_hourly_noncamd.csv	Hourly CEM data replacing data in CAMD	C2.1CONUSv2.7_ertac_nonCAMD_hourly.csv Same for all years
	Added MO unit to correct hourly data that was reported in the wrong units (kW instead of GW)	
ertac_initial_uaf.csv	Unit Availability File	C2.1CONUSv2.7_20XX_ertac_initial_uaf.csv (based on final Sept 2017 documentation file.) Same for all years Files were run through the file converter to create the new code input file, ertac_initial_uaf_v2.csv
ertac_control_emissions.csv	Annual Control File	C2.1CONUSv2.7ref_20XX_ertac_control_emissions.csv, C2.1CONUSv2.7opt_ertac_control_emissions.csv (based on final Sept2017 controls file) Same for all years.
	For 2.7, two control files were used. One is the reference case (ref) that includes only those controls supplied by states. One is an optimized file (opt) that removes certain SCR/SNCR coal fired units and certain OK units since they were moved to the seasonal controls file.	
ertac_seasonal_control_emissions.csv	Seasonal Control File	C2.1CONUSv2.7ref_20XX_ertac_control_emissions.csv (based on final Sept2017 controls file) and C2.1CONUSv2.7opt_20XX_ertac_control_emissions.csv Same for all years. For 2.7, two seasonal control files were used. One is the reference case (ref) that includes only those controls supplied by states. One is an optimized file (opt) that includes state data as well as additional ozone season information for certain SCR/SNCR coal fired units and certain OK units. For the optimized units, only OS NOx rates were reduced. NOx rates in other months were left equivalent to reference case information.
	For 2.7, two seasonal control files were used. One is the reference case (ref) that includes only those controls supplied by states. One is an optimized file (opt) that includes state data as well as additional ozone season information for certain SCR/SNCR coal fired units and certain OK units. For the optimized units, only OS NOx rates were reduced. NOx rates in other months were left equivalent to reference case information.	
ertac_growth_rates.csv	Growth Files	C2.7CONUSv2.7ref_20XX_ertac_growth_rates.csv
	Based on AEO 2017 no CPP rates. Used NYCW and SRVC specific growth rates. NYCW did not have updated values. SRVC provided updated values.	
ertac_input_variables.csv	Input Variables File	C2.7CONUSv2.7ref_20XX_ertac_input_variables.csv Code 1.01 files were run through the file converter to create the Code 2.1 input file called ertac_input_variables_v2.csv
ertac_demand_transfer.csv	Transfers of power between regions, fuel/unit types, into or out of systems from renewables and nuclear, etc	C2.7CONUSv2.7ref_20XX_ertac_demand_transfer.csv. Different for all years.
group_total_listing.csv	Aggregation scheme for multi-state caps	C2.7CONUSv2.7ref_20XX_group_total_listing.csv (same for all years) Updated to include latest CSAPR update values
state_total_listing.csv	Aggregation scheme for state level caps	C2.7CONUSv2.7ref_20XX_state_total_listing.csv (same for all years) Updated to include latest CSAPR update assurance level values.

ERTAC File Name	Description	Run Notes
OVERVIEW	Version: 2.7 Reference	Run by VA DEQ - Doris McLeod Sep 2017.
	Code: 2.1	
	Base Year: 2011	Update to UAF, Controls, and nonCAMD hourly. States feedback deadline: June, 2017.
	Future Years: 2020, 2021, 2023, 2025, 2028, and 2030	
camd_hourly_base.csv	Hourly CAMD CEM data	
ertac_hourly_noncamd.csv	Hourly CEM data replacing data in CAMD	C2.1CONUSv2.7_ertac_nonCAMD_hourly.csv
	Updates include adding one hour of reasonable, minimal data to approximately 44 units that Emily Bull (MDE) identified as missing in output files to allow the tool to process these units fully.	
ertac_initial_uaf.csv	Unit Availability File (XX denotes year, example 17 = 2017)	C2.1CONUS2.7_20XX_ertac_initial_uaf.csv: Updates include state inputs and regional boundaries for MROS.
ertac_control_emissions.csv	Annual Control File (XX denotes year, example 17 = 2017)	CONUSv2.7ref_20XX_05052016_ertac_control_emissions.csv
ertac_seasonal_control_emissions.csv	Seasonal Control File (XX denotes year, example 17 = 2017)	C2.1CONUSv2.7_20XX_ertac_seasonal_control_emissions.csv
	Seasonal controls provided by VA, GA, PA (Brunner Island Units 1, 2 & 3 have lower NOX and SO2 rates during the ozone season to represent NG firing.) and MD & NJ	
ertac_growth_rates.csv	Growth Files (XX denotes year, example 17 = 2017)	CONUSv2.7ref_20XX_05052016_ertac_growth_rates.csv
	ANNUAL GROWTH rates spreadsheet supplied by T. Shanley of MI DEQ called AEO2017 GRs.xlsx. Adjustments to	
		SRVC - Peak and annual growth rates supplied by NC for SC, NC, VA and WV.
		NYCW - GRs supplied by NY in memo to MARAMA.
	PEAK GROWTH Rate spreadsheet supplied by T. Shanley (MI) called Gas_Adj_AEO2014_NERC2013 Growth Rates v4	
		SRGW peak growth rate for oil was set to 2.0 to ameliorate an extremely high peak rate, per LADCO.
		SRSE peak GRs and transition hours adjusted for Coal, CC, SC, BG as in Lopez (MI) email to Byeong Kim (GA) 7/20/2017 with subject "SRSE Peak Growth Rate Adjustments"
		COMBINED CYLE GAS: Ameleoration of GDUs created solely for Peak hour demand deficits
		RFCM, MROZ, and MROW combined cycle peak growth rate set to 1.3 and transition hours peak->formula set to 200; formula-> nonpeak set to 2000 based on LADCO, WI, and MI input. All other transition hours remain at default levels.
		CAMX, ; NWPP; RFWZ; SRCE; SRGW Combined cycle gas peak 2028 GR set to 1.3 and transition hours set to 200 and 2000.
	EMM to NERC Crosswalk	SPPR – Two AEO regions, SPPN and SPPS, were aggregated for the coal fuel type only.
ertac_input_variables.csv	Input Variables File (XX denotes year, example 17 = 2017)	C2.1CONUSv2.7_20XX_ertac_input_variables.csv
group_total_listing.csv	Aggregation scheme for multi-state caps (XX denotes year, example 17 = 2017)	C2.1CONUSv2.7_20XX_group_total_listing.csv
state_total_listing.csv	Aggregation scheme for state level caps (XX denotes year, example 17 = 2017)	C2.1CONUSv2.7_20XX_state_total_listing.csv

References

ERTAC 2017a – Change log

ERTAC 2017b – New Code Document.

Vinciguerra et al., Expected Ozone Benefits of Reducing Nitrogen Oxide (NOx) Emissions from Coal-Fired Electricity Generating Units in the Eastern United States.

US Energy Information Administration 2017, *Annual Energy Outlook 2017 with Projections to 2050*, accessed from https://www.eia.gov/outlooks/aeo/.

MINNESOTA POLLUTION CONTROL AGENCY

Attachment 3:

Public notice

Minnesota Pollution Control Agency
Environmental Analysis and Outcomes Division
Public Notice on State Implementation Plan Revision

NOTICE IS HEREBY GIVEN that the Commissioner of the Minnesota Pollution Control Agency (MPCA) has determined that a State Implementation Plan (SIP) revision must be submitted to meet Minnesota's requirements under sections 110(a)(1), 110(a)(2), and 128 of the Clean Air Act (the Act). The draft SIP revision is now available for public comment.

Background. Sections 110(a)(1) and 110(a)(2) of the Act require that states prepare and submit to the U. S. Environmental Protection Agency (EPA) an "infrastructure" SIP within three years of the EPA's issuance of a new National Ambient Air Quality Standard (NAAQS) to demonstrate their continued ability to implement, maintain, and enforce the revised standards. This infrastructure SIP submission addresses the 2015 ozone NAAQS.

Purpose of the SIP revision. The purpose of this SIP revision is to fulfill Minnesota's responsibility under the Act to demonstrate its ability to implement, maintain, and enforce the revised ozone NAAQS cited above. This includes information about Minnesota's air quality programs such as monitoring, permitting, and modeling. Many of these requirements have already been submitted as part of the SIP.

The MPCA will consider changing the contents of the proposed SIP revision based on comments received during the comment period. Following the end of the comment period, the Commissioner will decide whether to submit the proposed SIP revision to the EPA.

MPCA contact person. The MPCA contact person is Christine Steinwand. Written comments, requests, and petitions should be mailed to: Christine Steinwand, Minnesota Pollution Control Agency, Environmental Analysis and Outcomes Division, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194; telephone: 651-757-2327 or toll free 1-800-657-3864; fax: 651-297-8324; and email: Christine.Steinwand@state.mn.us. TTY users may call the MPCA at TTY 651-252-5332 or 1-800-657-3864.

Availability of SIP. A copy of the proposed SIP revision is available on the MPCA's web site at http://www.pca.state.mn.us/public-notices. A copy of the proposed SIP revision is also available upon request by contacting Christine Steinwand at 651-757-2327 or Christine.Steinwand@state.mn.us, or can be mailed to any interested person upon the MPCA's receipt of a written request. Additional materials relating to the SIP revision are available for inspection by appointment at the MPCA, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194, between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday. To examine these materials, or for more information, please contact Christine Steinwand. All MPCA offices may be reached by calling 1-800-657-3864.

Public comment period and potential public meeting. The public comment period begins July 9, 2018 and ends on August 10, 2018. Your comments must be in writing and received by Christine Steinwand by 4:30 p.m. on August 10, 2018. Written comments may be submitted to them at the mailing address, facsimile number, or e-mail address listed above.

As this SIP revision does not include any substantive changes to the Minnesota's SIP, a public information meeting will only be held if one is requested by 4:30 p.m. on August 10, 2018. If such a meeting is requested, it will be held on August 16, 2018 from 9:00 a.m. to 11:00 a.m. at the MPCA St. Paul Office, 520 Lafayette Road North, St. Paul, Minnesota 55155-4194. To find out if a public information meeting will be held, please contact Christine Steinwand at 651-757-2327 or Christine.Steinwand@state.mn.us after August 10, 2018 at 4:30 p.m. The public information meeting, if one is requested, will provide information, receive public input, and answer questions about the proposed SIP revision. If the public information meeting is held, additional written comments on the proposed documents will be accepted until 4:30pm on August 24, 2018, following the same guidelines described above.

MINNESOTA POLLUTION CONTROL AGENCY

Attachment 4:

Completeness review

Attachment 4: Completeness Review

Contents

A. Administrative Materials (40 CFR pt. 51, Appendix V, Part 2.1)

The EPA's Criteria for Determining the Completeness of Plan Submittals, published at 40 CFR part 51, Appendix V, requires states to provide the basic documents that show that the State has properly followed the administrative requirements called for by the CAA for the adoption of SIPs. The requirements, and how this SIP revision complies with these requirements, are discussed here:

1) Formal Letter of Submittal:

> "A formal letter of submittal from the Governor or his designee, requesting EPA approval of the plan or revision thereof."

Attached to this SIP revision request is a formal letter of submittal from the MPCA Commissioner, John Linc Stine, to the EPA Region V Administrator, Cathy Stepp. The office of the Commissioner of the MPCA is statutorily created in Minnesota Statute § 116.03, subd. 1 (a). The Commissioner is appointed by the Governor, and the duties of the position include acting as the state agent to "apply for, receive, and disburse federal funds made available to the state by federal law or rule and regulations promulgated thereunder for any purpose related to the power and duties of the MPCA or the Commissioner. The Commissioner shall comply with any and all requirements of such federal law or such rules and regulations promulgated thereunder to facilitate application for, receipt, and disbursement of such funds." Minn. Stat. § 116.03 subd. 3.

2) Evidence of State Adoption of Plan and Issuance of Orders in Final Form:

> "Evidence that the State has adopted the plan in the State code or body of regulations; or issued the permit, order, consent agreement (hereafter 'document') in final form. That evidence shall include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date."

The rules and statutes documented in this submittal have previously been incorporated into Minnesota's SIP, and/or approved under the auspices of an iSIP [Sections 110(a)(1) and 110(a)(2) of the Clean Air Act].

3) Legal Authority Documentation:

> "Evidence that the State has the necessary legal authority under State law to adopt and implement the plan."

This SIP submittal documents the MPCA's legal authority in addressing the requirements of Section 110(a)(1) of the Clean Air Act.

4) Compliance with State Procedures:

> "Evidence that the state followed all of the procedural requirements of the State's laws and constitution in conducting and completing the adoption/issuance of the plan."

MPCA complied with all relevant state procedures for issuing the permit as well as the SIP revision.

5) Public Notice:

> "Evidence that public notice was given of the proposed change consistent with the procedures approved by the EPA, including the date of the publication of the notice."

The public notice for the SIP revision was published in the State Register on July 9, 2018 with the public comment period commencing on July 9, 2018 and ending on August 10, 2018. During the public comment period, a copy of the SIP revision was made available at the MPCA office located in St. Paul and on the MPCA's website. A copy of the public notice is attached (Attachment 3).

6) Public Hearing Certification:

> "Certification that public hearing(s) were held in accordance with the information provided in the public notice and the State's laws and constitution, if applicable."

The public notice states: "As this SIP revision does not include any substantive changes to the Minnesota's SIP, a public information meeting will only be held if one is requested by 4:30 p.m. on August 10, 2018. If such a meeting is requested, it will be held on August 16, 2018 from 9:00 a.m. to 11:00 a.m. at the MPCA St. Paul Office, 520 Lafayette

Road North, St. Paul, Minnesota 55155-4194. To find out if a public information meeting will be held, please contact Christine Steinwand at 651-757-2327 or Christine.Steinwand@state.mn.us after August 10, 2018 at 4:30 p.m. The public information meeting, if one is requested, will provide information, receive public input, and answer questions about the proposed SIP revision. If the public information meeting is held, additional written comments on the proposed documents will be accepted until 4:30pm on August 24, 2018, following the same guidelines described above."

[This section will be completed after the comment period ends to reflect whether or not a public hearing was requested and/or held.]

7) Public Comments and State Response:

> "Compilation of the public comments and State's response thereto."

[This section will be completed after the comment period ends to reflect what, if any, comments were received.]

B. Technical Support

1) Pollutants Regulated:

> "Identification of all regulated pollutants affect by the plan."

This infrastructure SIP submission addresses the 2015 ozone NAAQS.

2) Source Identification:

> "Identification of the locations of affected sources including the EPA attainment/nonattainment designation of the locations and the state of the Attainment Plan for the affected area(s)."

Does not apply to this SIP submittal.

3) Emissions Quantification:

> "Quantification of the changes in the plan; allowable emissions from the affected sources; estimates of changes in current actual emissions from affected sources or, where appropriate, quantification of the changes in actual emissions through calculations of the differences between certain baseline levels and allowable emissions anticipated as a result of the revision."

Does not apply to this SIP submittal.

4) NAAQS Protections:

> "The State's demonstration that the NAAQS, prevention of significant deterioration increments, reasonable further progress demonstration, and visibility, as applicable, are protected if the plan is approved and implemented."

The purpose of this SIP submittal is to demonstrate Minnesota's ability to implement, maintain, and enforce the revised NAAQS.

5) Modeling Information:

> "Modeling information required to support the proposed revision, including input data, output data, models used, justification of the model selections, ambient monitoring data used, meteorological data used, justification for use of off-site data (where used), modes of models used, assumptions, and other information relevant to the determination of adequacy of the modeling analysis."

Does not apply to this SIP submittal.

6) Continuous Emission Reduction:

> "Evidence, where necessary, that emission limitations are based on continuous emission reduction technology."

Does not apply to this SIP submittal.

7) Emission Level Assurance:

> "Evidence that the plan contains emission limitations, work practice standards and recordkeeping/requirements, where necessary, to ensure emissions levels."

The purpose of this SIP submittal is to demonstrate Minnesota's ability to implement, maintain, and enforce the revised NAAQS.

8) Compliance/Enforcement:

> "Compliance and enforcement strategies, including how compliance will be determined in practice."

The purpose of this SIP submittal is to demonstrate Minnesota's ability to implement, maintain, and enforce the revised NAAQS.

9) Special Economic and Technological Justifications:

> "Special economic and technological justifications required by any applicable EPA policies, or an explanation of why such justifications are not necessary."

Does not apply to this SIP submittal.

Attachment C

(Alpine Geophysics Report)

TECHNICAL REVIEW OF THE ENVIRONMENTAL PROTECTION AGENCY'S AIR QUALITY MODELING AND ENGINEERING ANALYTICS BUDGET ALLOCATION DATA FILES SUPPORTING THE FEDERAL "GOOD NEIGHBOR PLAN" FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

Prepared by:
Alpine Geophysics, LLC
August 2023

Certified by:

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A. Objective

The objective of this document is for Alpine Geophysics, LLC ("Alpine") to report our determination whether there are discrepancies in EPA's air quality modeling, significant contribution calculations, or allocation of allowances to emission units in upwind states linked to the Alsip Village Garage monitor (170310001) in Cook County, Illinois, the lone monitor that links Minnesota to Good Neighbor Rule obligations, and whether EPA's methods have more widespread errors that indicate a problem with these elements as applied to Minnesota.

For Minnesota, we would expect the photochemical grid modeled (PGM) emissions to be reasonably close to historic CEMS emissions because EPA is not modeling significant emission reductions. If the PGM emission input values are significantly higher, EPA may be mischaracterizing an attaining monitor as "maintenance only." We would also expect that the budgeted emissions for the trading program would be reasonably close to historic facility-level emission monitoring data and the PGM emission input values. To the extent these values are not reasonably close, it is an indication that EPA's use of different datasets is not neutral as applied to Minnesota.

As part of this analysis, Alpine compared electric generating units (EGUs) from Indiana, Michigan, Minnesota, Texas, and Wisconsin used in EPA's air quality modeling and to those in EPA's budget allocation determinations. Alpine notes that four separate data files are used in various areas of the analyses supporting the FIP and in this document we directly compare two of these files. Alpine has identified when sources are in one of the data files and not the other or when major discrepancies exist between the two.

B. Background

In developing the air quality improvements associated with proposed EGU and non-EGU controls of the final ozone transport FIP rule, EPA used multiple, sometimes inconsistent, data because it was convenient and readily available.

EPA started by calculating an ozone change factor between two 2026 future year simulations from the proposed ozone transport FIP rule (version 2 platform[1] – **first data set**). These two simulations differ in the fact that NOx emissions are reduced by 30% for both EGU and non-EGU sources in all states in the second non-base case simulation. The change in ozone concentration

[1] EPA-HQ-OAR-2021-0668-0064

at each downwind receptor divided by the change in upwind NOx emissions from the EGU and non-EGU point sources determined the ratio, or calibration, used by EPA[2]. From a Minnesota specific perspective, not only is Minnesota not linked to any monitor in EPA's 2026 base case calculations and by which the calibration factors are estimated, Minnesota is also not required to control emissions from any non-EGU sources in 2026. In addition, this 2026v2 platform also improperly characterizes emissions from Minnesota EGU sources that are fully expected to operate in 2026. EPA's emission EGU projection with the Integrated Planning Model (IPM) chose to zero out emissions from these units thereby removing their potential reduction impact from the calibration calculation. As a result, it is probable that the reactivity included in the calibration factor is compromised because all expected emissions from the state are not adequately characterized in the factor.

To apply these calibration factors to determine the impact of emission reductions on base case ozone concentrations, EPA utilized a **second set** of data from the final rule (version 3 modeling platform)[3]. Note that this updated platform, in addition to including alternate anthropogenic emissions from many states and categories, also utilized alternate boundary condition emissions (e.g., international transport), updated biogenic emissions estimates, and included NOx emissions from lightning strikes; all elements that EPA attempts to neutralize the differences by using more calibration factor adjustments. The 2023 base case projection from this version 3 was used to identify future year nonattainment or maintenance monitors, significant contribution values from each upwind state to downwind receptors, and to select the top modeled days that are used in the change in concentration/change in emissions calibration calculations. As noted above, while the 2026v2 calibration calculation did not contain properly characterized emissions from various Minnesota EGU sources, the 2023v3, and associated design values, significant contribution metrics, and top modeled days do contain these sources.

To develop the estimated emission reductions associated with the various control options proposed by EPA, the agency used yet a **third set** of EGU data[4], historical CEM-reported heat input (a.k.a., Engineering Analytics or EA), emission rates, and calculated emissions from 2017-2021. This third set of emissions differs again from both the first and second sets in the fact that IPM was not used to forecast emissions beyond current years. From this third set, and another 2023 forecast, the impact of emission rates was calculated and emission differences between a base simulation and controlled simulation was calculated. Again, it is important to note that units presumed to be in operation in this third set of projections were estimated with alternate

[2] EPA-HQ-OAR-2021-0668-1080
[3] EPA-HQ-OAR-2021-0668-1000
[4] Appx. A, EPA-HQ-OAR-2021-0668-1080

emission projections to either the v2 or v3 projections from IPM, used in the calibration calculation and the final rule attainment designation process. The emissions budgets assigned to sources with this EA data calculation were then used to estimate the air quality impact of the final rule.

When EPA eventually puts the pieces together, these seemingly incongruous factors are applied to each other. The emissions delta from the **third set** of data is scaled to a change in ozone/ton of NOx reduced using the calibration factor from the **first set of data** and then applied to the ozone concentrations and emissions included in the **second set** of data. The resulting concentration values, while seemingly directionally consistent with the anticipated change in emissions, are unverified using an independent photochemical model run (EPA's preferred method[5]) and instead are corroborated by EPA utilizing yet another calibration simulation[6].

Finally, a **fourth set of data[7]** was used to estimate the costs associated with the optimization of SCR and SNCR control on units which already have these post-combustion controls installed. Using parameters from an October 2021 version of IPM's NEEDS input file (held constant from the proposed rule), unit specific characteristics were used to evaluate costs from this optimization step. Of note, costs for units optimized in Minnesota are estimated to have cost per ton values higher than the final FIP range of accepted values.

C. Specific Comparison in this Document

The EPA projected 2023 and 2026 baseline EGU emissions using version 6—Updated Summer 2021 Reference Case of the Integrated Planning Model (IPM)[8]. IPM is described by EPA as a state-of-the-art, peer-reviewed, multi-regional, dynamic, deterministic linear programming model of the contiguous U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emissions control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints.

Additionally, 2023 through 2026 EGU emissions baseline levels were developed through engineering analytics as an alternative approach that did not involve IPM. The EPA developed this inventory for use in determining emission reduction potential and corresponding state-level emissions budgets.

[5] https://www.epa.gov/system/files/documents/2022-03/aq-modeling-tsd_proposed-fip.pdf
[6] EPA-HQ-OAR-2021-0668-1080
[7] EPA-HQ-OAR-2021-0668-0996
[8] https://www.epa.gov/power-sector-modeling

EPA has articulated[9] a ''4-step framework'' within which to assess interstate transport obligations for ozone. In the FIP rule to address interstate transport obligations for the 2015 ozone NAAQS, the EPA is again utilizing the 4-step interstate transport framework. These steps are:

(1) identifying downwind receptors that are expected to have problems attaining the NAAQS (nonattainment receptors) or maintaining the NAAQS (maintenance receptors);
(2) determining which upwind states are ''linked'' to these identified downwind receptors based on a numerical contribution threshold;
(3) for states linked to downwind air quality problems, identifying upwind emissions on a statewide basis that significantly contribute to downwind nonattainment or interfere with downwind maintenance of the NAAQS, considering cost- and air quality-based factors; and
(4) for upwind states that are found to have emissions that significantly contribute to nonattainment or interfere with maintenance of the NAAQS in any downwind state, implementing the necessary emissions reductions through enforceable measures.

By using IPM at Step 1 and 2, EPA indicates it is selecting the more conservative approach for identifying the degree of nonattainment and geography of states contributing above 1 percent. By using Engineering Analytics at Step 3, EPA indicates that it is selecting the more conservative value to codify into state-level budgets.[10]

EPA explains in the final rule preamble why these techniques are considered appropriate for the purposes at each step of the analysis, and why they are not incompatible, nor do they produce results so different as to call into question their reliability or the bases for EPA's regulatory determinations. EPA states that the nationwide projected ozone season total NOx emissions vary by less than 1 percent in the 2023 analytic year, however, EPA is silent as to a comparison of important sub-regional and unit emission rates, including differences detailed in this document that demonstrate variance of significantly greater than 1 percent for the emission rates relevant to Minnesota.

D. Review of Data Used by U.S. EPA

1. EPA's 2016v3 Modeling Platform Inventories

[9] See CSAPR, Final Rule, 76 FR 48208, 48248– 48249 (August 8, 2011); CSAPR Update, Final Rule, 81 FR 74504, 74517–74521 (October 26, 2016).
[10] 88 FR 36700

The EPA used version 3 of the 2016-based air quality modeling platform[11] (i.e., 2016v3) to provide the foundational model-input data sets for 2016, 2023, and 2026.

The 2023 and 2026 electric generating unit (EGU) emissions inventories from the FIP modeling platform used the outputs of the EPA's Updated Summer 2021 Reference Case of the Integrated Planning Model (IPM). [12] The projections are calculated using the ratio of the analytic year seasonal generation in the IPM parsed file and the base year seasonal generation at each unit for each fuel type in the unit as derived from the 2018 EIA-923 tables and the 2018 NEI. New controls identified at a unit in the IPM parsed file are accounted for with appropriate emissions reductions as estimated by the model using cost-minimization functions. Both environmental and economic compliance rules placed on these units are based on future year scenarios configured by EPA.

IPM generates EGU emissions using data from continuous emissions monitoring systems (CEMS) and other monitoring systems allowed for use by qualifying units under 40 CFR part 75, with other EGU pollutants estimated using emissions factors and annual heat input data reported to the EPA. For EGUs not reporting under Part 75, the EPA used data submitted to the NEI by the state, local, and tribal agencies.

Throughout all of the CSAPR rules to date, and prior interstate transport actions, the EPA has used IPM at Steps 1 and 2 as they state it is best suited for projecting emissions in an airshed, projecting emissions for time horizons more than a few years out (for which changes would not yet be announced and thus projecting changes is critical), and for scenarios where the assumed change in emissions is not being codified into a state emissions reduction requirement.

The agency notes that using IPM at Steps 1 and 2 helps the EPA avoid overstating the current analytic year receptor values (Step 1) and future year linkages (Step 2) by reflecting reductions anticipated to occur within the airshed in the relevant timeframe.

2. EPA's Engineering Analytics Inventory

Additional 2023 through 2026 EGU emissions baseline levels were developed by EPA through Engineering Analytics (EA) as an alternative approach that did not involve IPM[13]. The EPA developed this inventory for use in Step 3 of this final rule, where it determined emissions reduction potential and corresponding state-level emissions budgets.

[11] EPA-HQ-OAR-2021-0668-1000
[12] 88 FR 36699
[13] Id

EPA adopted a similar approach to the CSAPR Update[14] and the Revised CSAPR Update[15] where it utilized historical data and an engineering analytics approach in Step 3. EPA justified this approach stating it was to avoid overstating optimization and dispatch decisions in state-emissions budget quantification that may not be possible in a short time frame. The EPA did this by starting with unit-level reported data and only making adjustments to reflect known baseline changes such as planned retirements and new builds (for the base case scenarios) and also identified mitigation strategies for determining state emissions budgets.

According to EPA, engineering analytics has been a useful tool for Step 3 state-level emissions reduction estimates in CSAPR rulemaking, because at that step the EPA is dealing with more geographic granularity (state-level as opposed to regional air shed), more near-term (as opposed to medium-term) assessments, and scenarios where reduction estimates are codified into regulatory requirements. EPA states that using the Engineering Analytics tool at this step ensures that the EPA is not codifying into the base case, and consequently into state emissions budgets, changes in the power sector that are merely modeled to occur rather than announced by real world actors.

Under the final rule, the determination of whether a unit is eligible to receive allocations as an “existing” unit or as a “new” unit varies across control periods. For the control periods in 2023 through 2025, a unit in a covered state meeting the CSAPR applicability criteria is treated as eligible to receive an allocation as an existing unit if the unit’s emissions were considered in the process for determining the state’s emissions budget for the respective control period in the final rule. Thus, if the unit was subject to requirements to report emissions and heat input under 40 CFR part 75 for the entire ozone season from May 1, 2021, through September 30, 2021, and reported any heat input greater than zero during that period, the unit is generally treated as eligible to receive an allocation as an existing unit for the control periods in 2023 through 2025.

For the existing units identified through the process detailed above, allocations for each control period are calculated using heat input and NOx emissions reported under either the CSAPR trading programs or the Acid Rain Program for a 5-year historical baseline period. To calculate allocations for the control periods in 2023 through 2025 in the final rule, EPA is using data reported for the control periods from 2017 through 2021. In each control period, the quantity of allowances allocated to existing units in a state using this methodology will be the portion of the state’s emissions budget remaining after subtraction of the new unit set-aside for the control period.

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[14] 76 FR 48208
[15] 81 FR 74504

E. Comparison and Issues

We compared EPA's IPM-generated EGU ozone season NOx emission projections with matched EGU units from the Engineering Analytics projections for CEM sources in Indiana, Michigan, Minnesota, Texas, and Wisconsin to determine if inconsistencies existed in how EPA developed emission projections for purposes of its Step 1, 2 and 3 of the transport frameworks.

EPA's IPM-generated emission estimates were obtained from the 2023 ozone season modeling platform files associated with the FIP air quality modeling analyses[16,17].

EA-generated emission estimates and budget allocation values were obtained from EPA-published spreadsheets found in the FIP docket[18].

What we found was that for many units, historical heat input/CEM-based emissions between 2017 and 2021 are significantly lower than those projected by EPA in 2023 (now a near term projection) and that were used to develop design value and significant contribution metrics.

Within each reviewed upwind state potentially affecting the Alsip/Village Garage Monitor, we investigated the top modeled units and the top emission allocated units for discrepancies between the two data platforms. Results for each are provided in the tables and graphs below.

Indiana

IPM projected emissions from the top 2023 base case unit (Clifty Creek Unit 6) in Indiana is almost 5.5 times higher than the maximum year monitored emissions reported between 2017-2021. Table 1 presents this information for this unit as well as similar information for the other highest IPM generated emission units in the state. The top 3 units with IPM-generated emissions are collectively almost 55% higher than the maximum average NOx emissions rate reported from 2017-2021.

The next three highest units presented in Table 1 are collectively 55% lower than the maximum CEM NOx emissions rate reported for the 2017-2021 period.

Figure 1 through Figure 7 present this information for multiple units listed in Table 1. Blue dots represent the historical ozone season NOx emissions from CEM-reported data (orange dot represents 2016 CEM also modeled by EPA), orange triangles represent the 2023 and 2026 IPM

[16] EPA-HQ-OAR-2021-0668-1000
[17] https://gaftp.epa.gov/Air/emismod/2016/v3/info_2016_v3_platform_package_with_2026gf_22may2023.txt
[18] EPA-HQ-OAR-2021-0668-0132

base case projected emissions, and grey diamonds represent the FIP published allowance allocations.

ALPINE GEOPHYSICS

	Ozone Season NOx Emissions (Tons)										
	CEM-Based										
Facility: Unit	2016	2017	2018	2019	2020	2021	Max (2017-2021)	EPA Allowance Allocation 2023	IPM-Generated 2023	% of Modeled Emissions (Step 1/2) Compared to Budget Emissions (Step 3)	% of Modeled Emissions (Step 1/2) Compared to Max Historical CEM
Clifty Creek:6	989	72	183	180	132	81	183	49	988	2016%	538%
Gibson:1	907	582	828	847	251	456	847	513	960	187%	113%
Gibson:4	748	674	625	320	795	331	795	527	866	164%	109%
Rockport:MB2	3,444	3,421	1,954	1,323	825	526	3,421	880	833	95%	24%
Gibson:3	1,399	534	955	282	1,079	323	1,079	501	827	165%	77%
Gibson:5	1,056	1,097	699	605	604	284	1,097	446	818	183%	75%
R M Schahfer Generating Station:18	527	969	726	578	540	762	969	330	722	219%	75%
Gibson:2	1,031	349	463	326	873	355	873	456	689	151%	79%
F B Culley Generating Station:2	256	98	157	98	50	152	157	57	656	1151%	419%
Alcoa Allowance Management Inc:4	1,452	328	1,162	1,119	1,514	645	1,514	320	648	202%	43%

Table 1. Historical CEM-based ozone season NOx emissions, EPA's EA-based allowance allocation, EPA's IPM generated 2023 emissions, and percentage comparison for top 2023 modeled Indiana units.

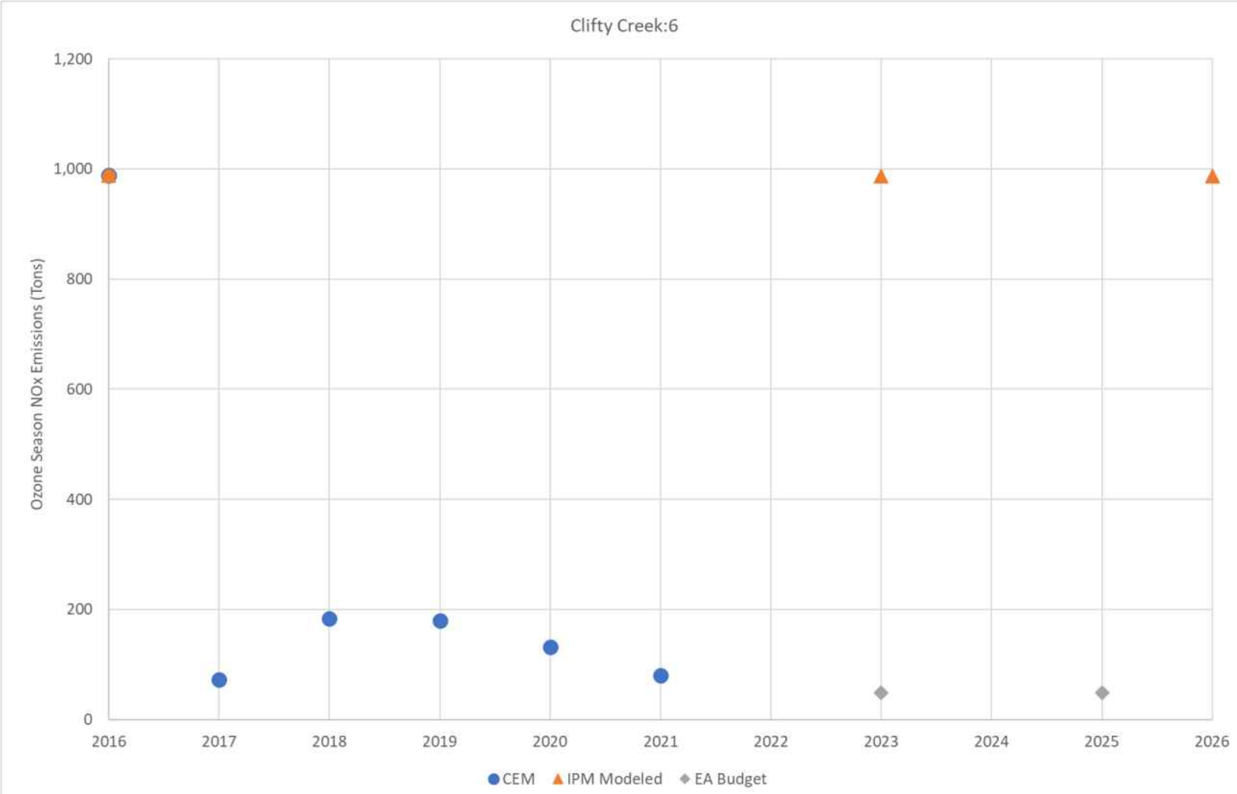

Figure 1. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Clifty Creek Unit 6.

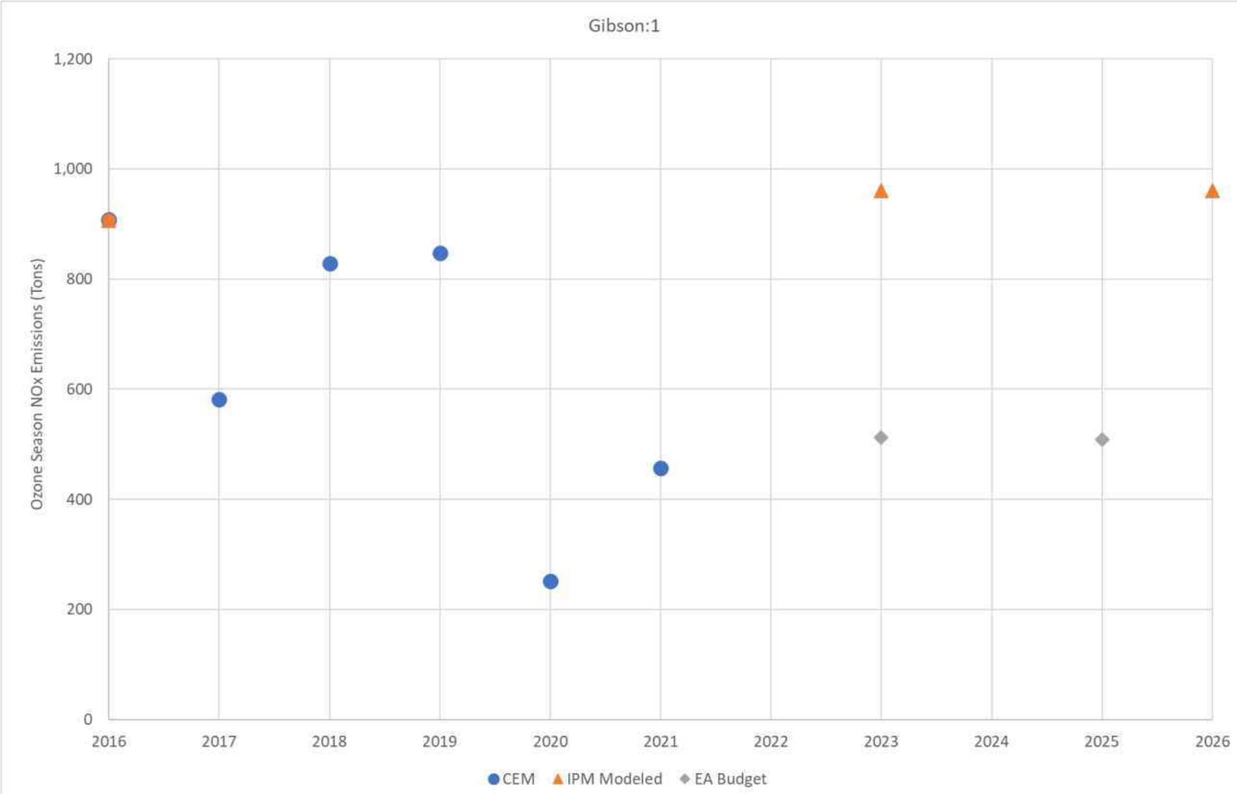

Figure 2. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Gibson Unit 1.

ALPINE GEOPHYSICS

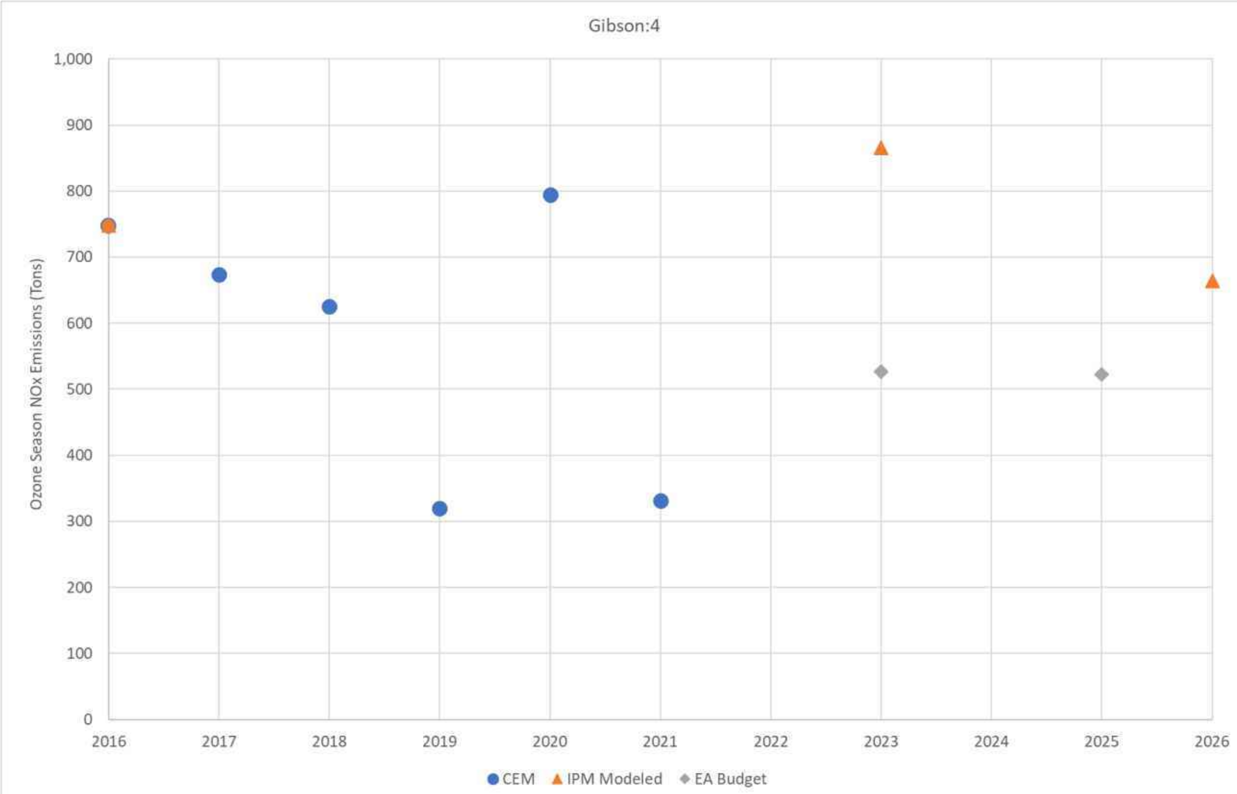

Figure 3. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Gibson Unit 4.

ALPINE GEOPHYSICS

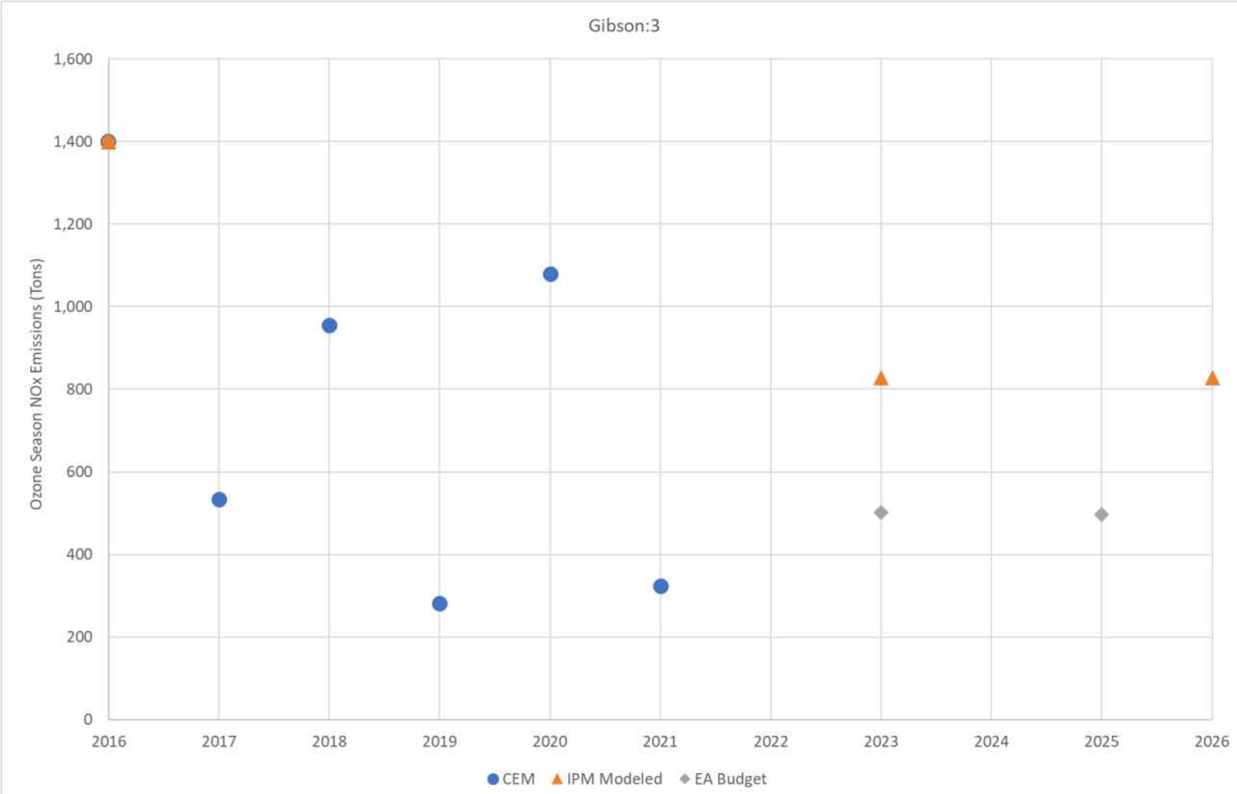

Figure 4. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Gibson Unit 3.

ALPINE GEOPHYSICS

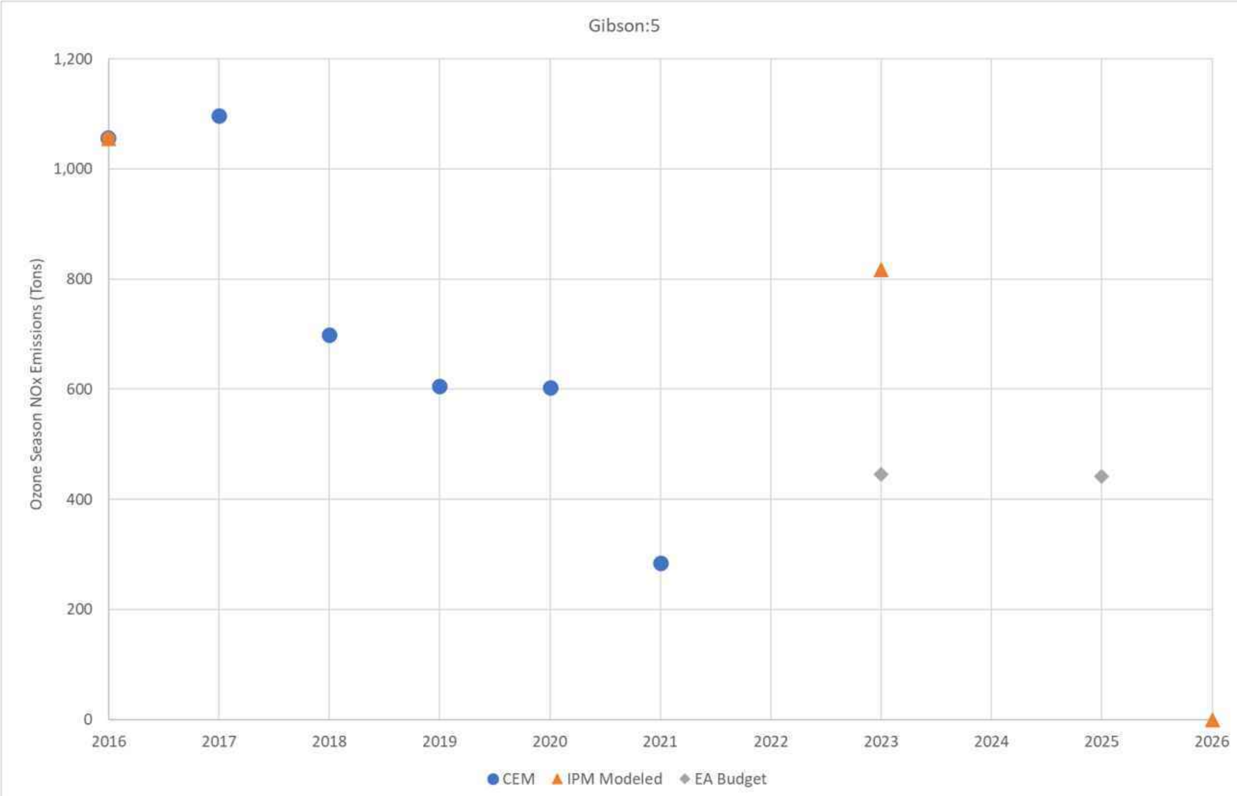

Figure 5. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Gibson Unit 5.

ALPINE GEOPHYSICS

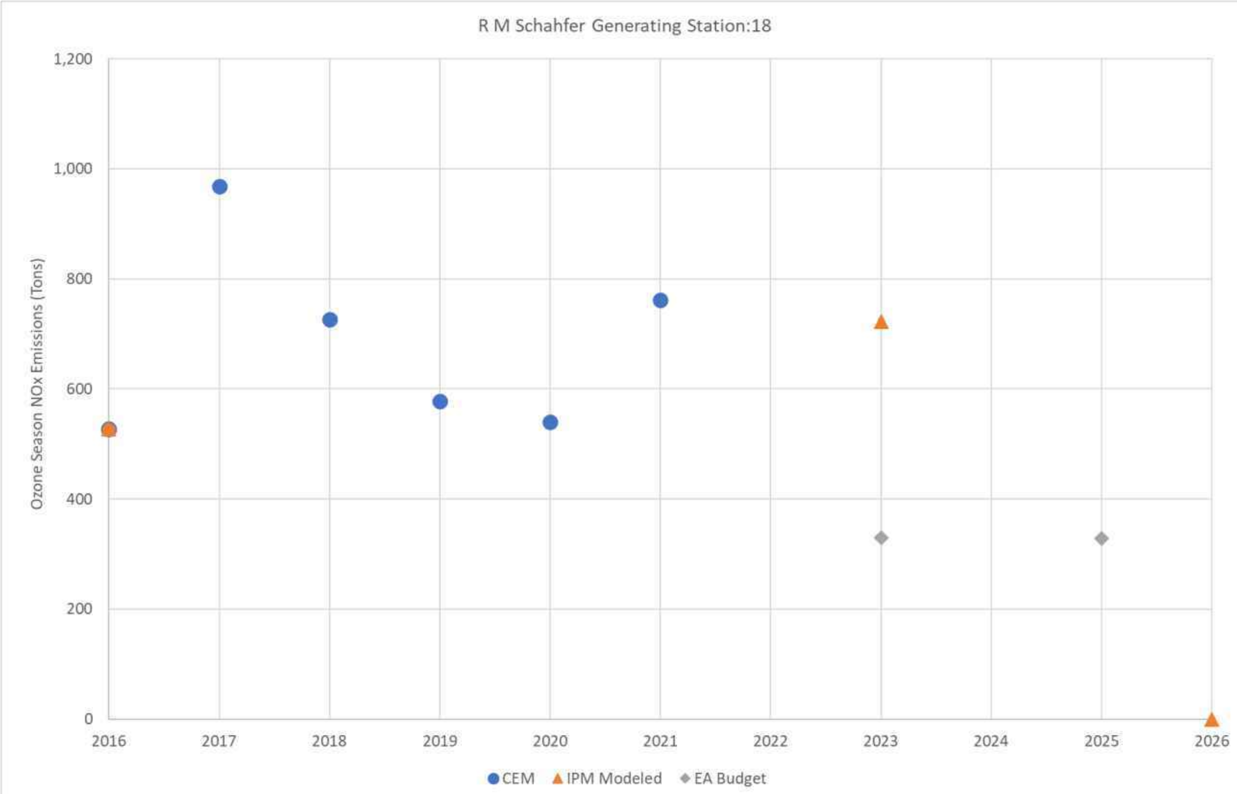

Figure 6. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the R M Schahfer Generating Station Unit 18.

ALPINE GEOPHYSICS

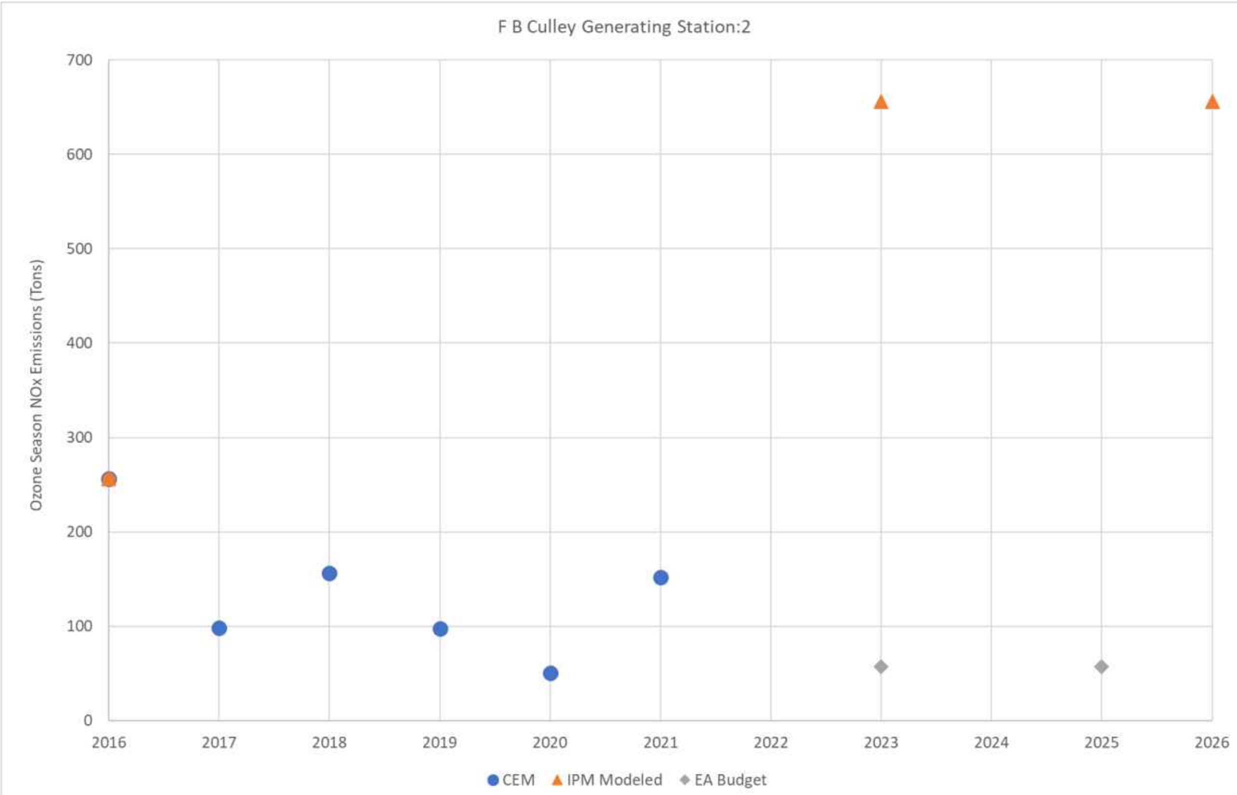

Figure 7. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the F B Culley Generating Station Unit 2.

Michigan

IPM projected emissions from the top 2023 base case units in Michigan are collectively 3.1 times higher than the maximum year monitored emissions reported between 2017-2021 for these same units. Table 2 presents this information for these units in the state. The top 3 units with IPM-generated emissions are collectively 3.6 times higher than the maximum average NOx emissions rate reported from 2017-2021 for these same sources and of these three, the top two were given no budget allocation in 2023 using the EA method as these units are identified as retired in 2023.

Figure 8 through Figure 14 present this information for multiple units listed in Table 2. Blue dots represent the historical ozone season NOx emissions from CEM-reported data (orange dot represents 2016 CEM also modeled by EPA), orange triangles represent the 2023 and 2026 IPM base case projected emissions, and grey diamonds represent the FIP published allowance allocations.

ALPINE GEOPHYSICS

	Ozone Season NOx Emissions (Tons)										
	CEM-Based										
Facility: Unit	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**Max (2017-2021)**	**EPA Allowance Allocation 2023**	**IPM-Generated 2023**	**% of Modeled Emissions (Step 1/2) Compared to Budget Emissions (Step 3)**	**% of Modeled Emissions (Step 1/2) Compared to Max Historical CEM**
St. Clair:7	518	66	776	580	407	731	776	0	1954	#N/A	252%
St. Clair:6	275	379	438	449	377	279	449	0	1875	#N/A	417%
Zeeland Generating Station:CC4	27	24	25	28	23	30	30	30	725	2416%	2425%
Midland Cogeneration Venture:018	0	3	0	0	1	4	4	4	236	5910%	6461%
Belle River:CTG131	9	8	14	16	10	5	16	16	55	342%	332%
Midland Cogeneration Venture:012	0	131	150	132	137	148	150	150	49	33%	33%
Midland Cogeneration Venture:010	0	97	162	173	123	89	173	151	49	33%	29%

Table 2. Historical CEM-based ozone season NOx emissions, EPA's EA-based allowance allocation, EPA's IPM generated 2023 emissions, and percentage comparison for top 2023 modeled Michigan units.

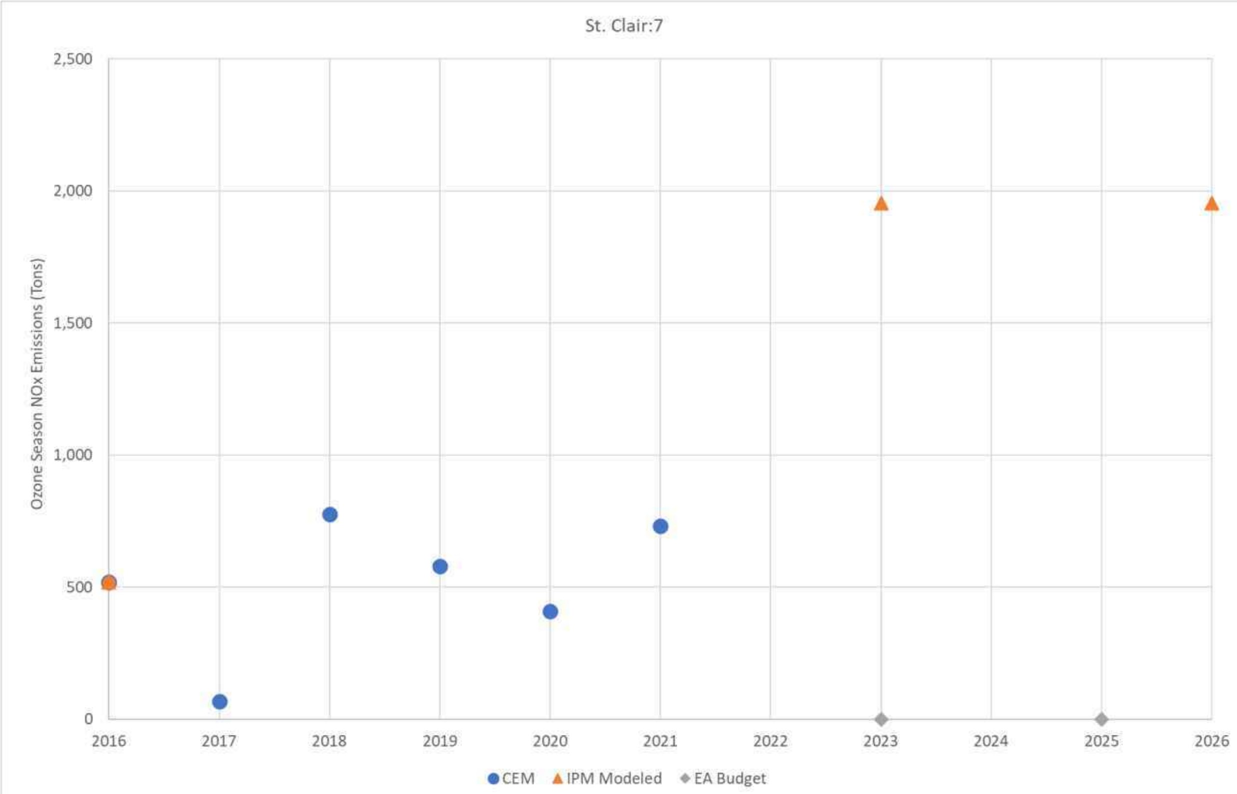

Figure 8. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at St. Clair Unit 7.

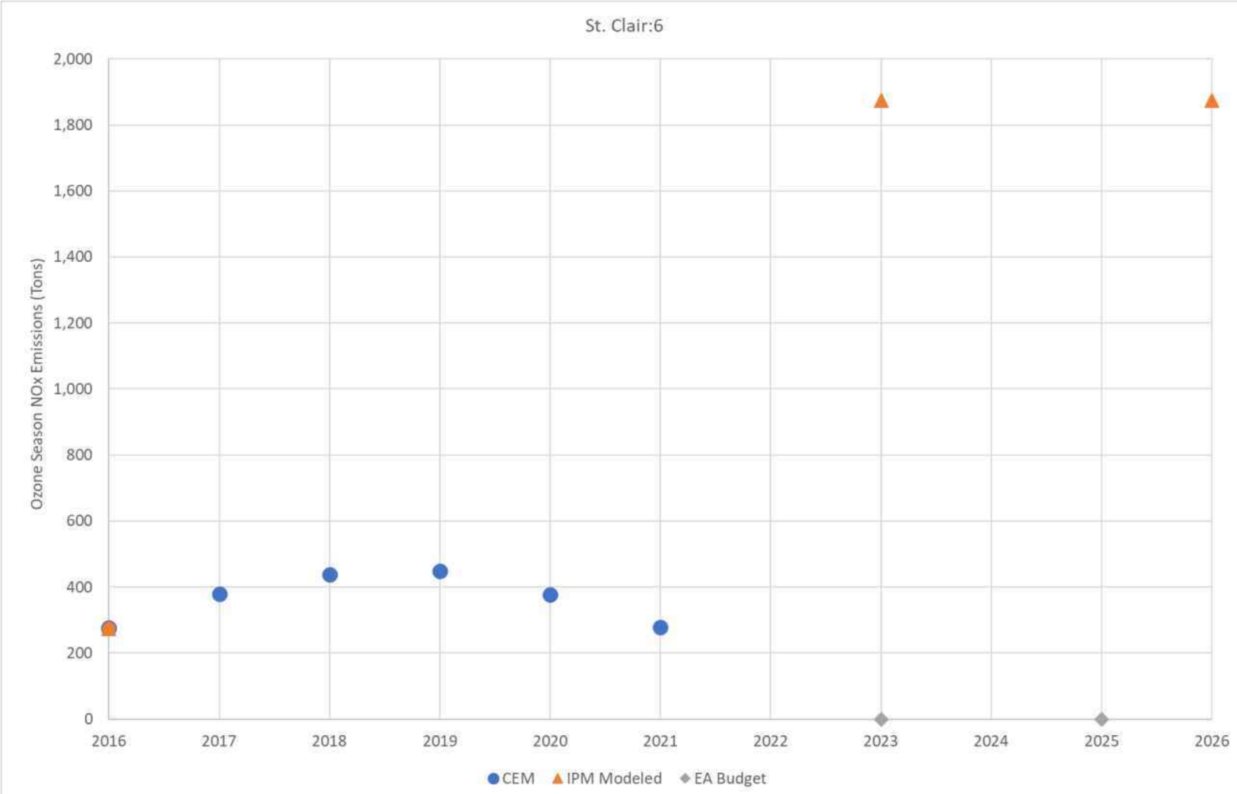

Figure 9. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at St. Clair Unit 6.

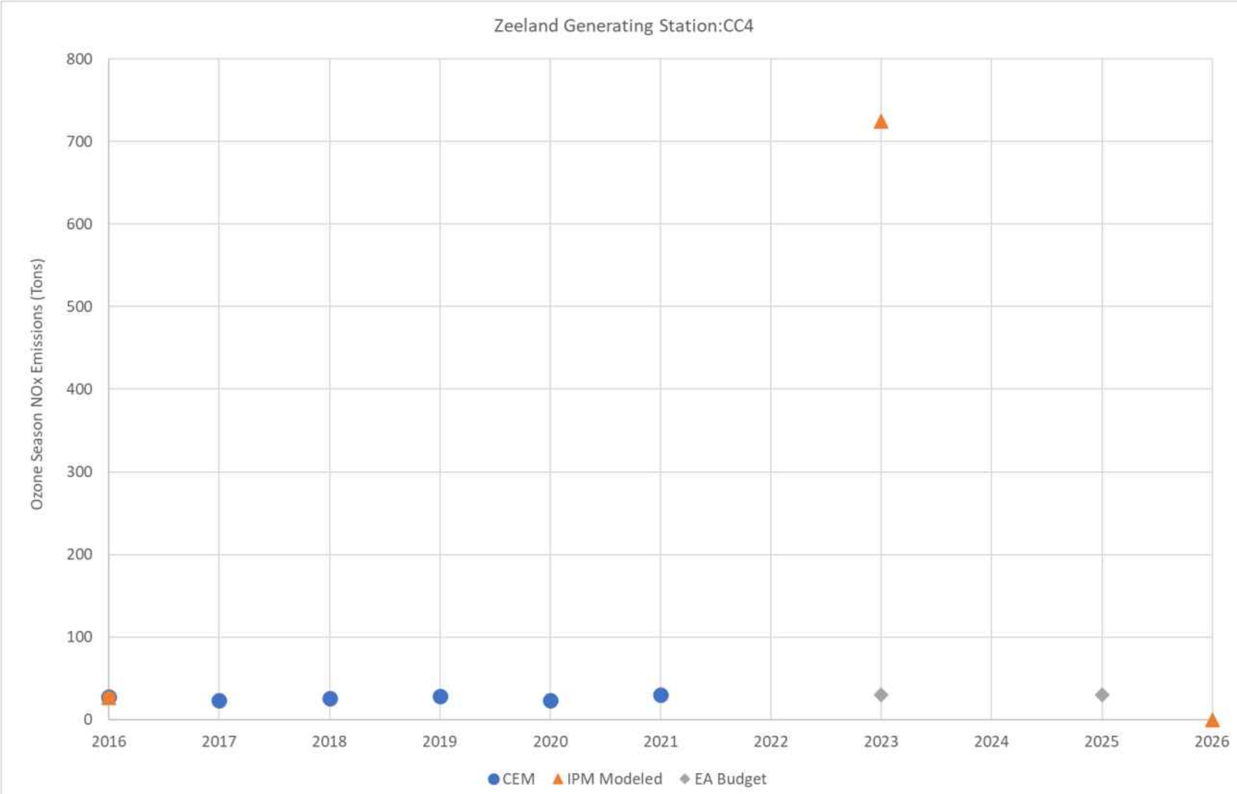

Figure 10. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Zeeland Generating Station Unit CC4.

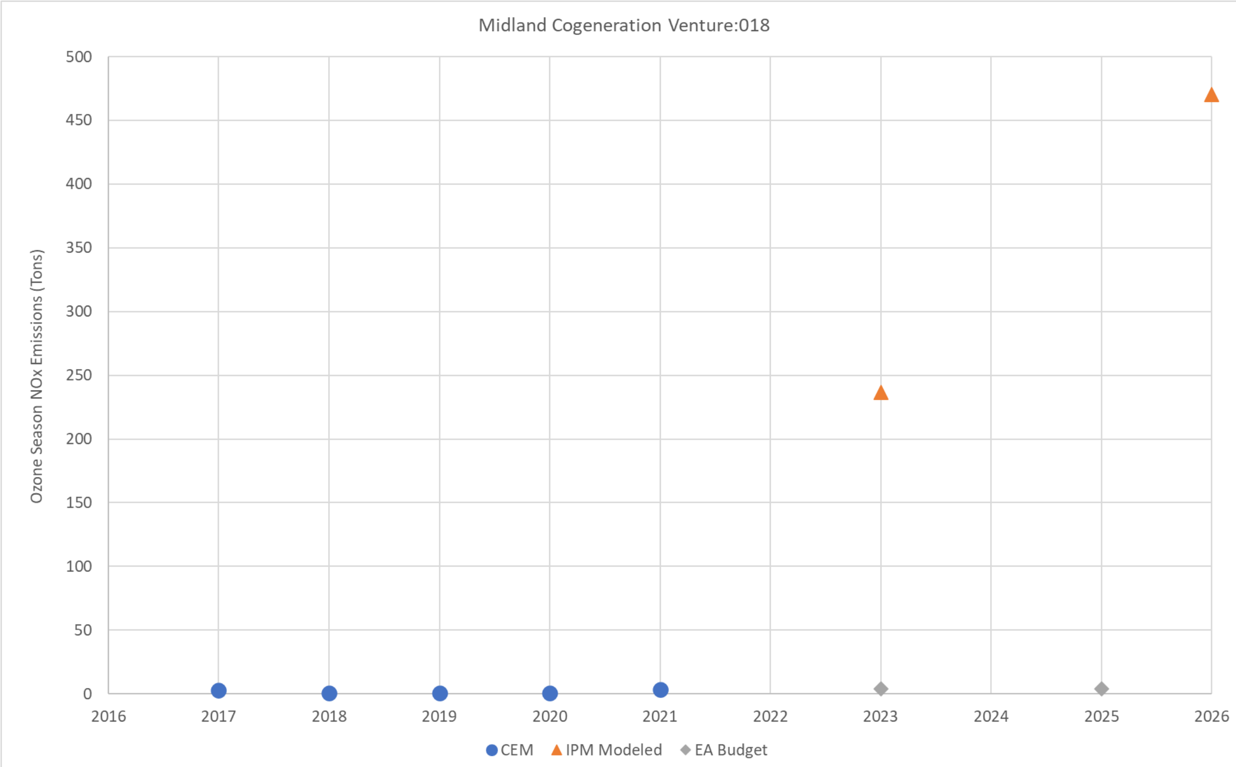

Figure 11. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Midland Cogeneration Venture Unit 018.

ALPINE GEOPHYSICS

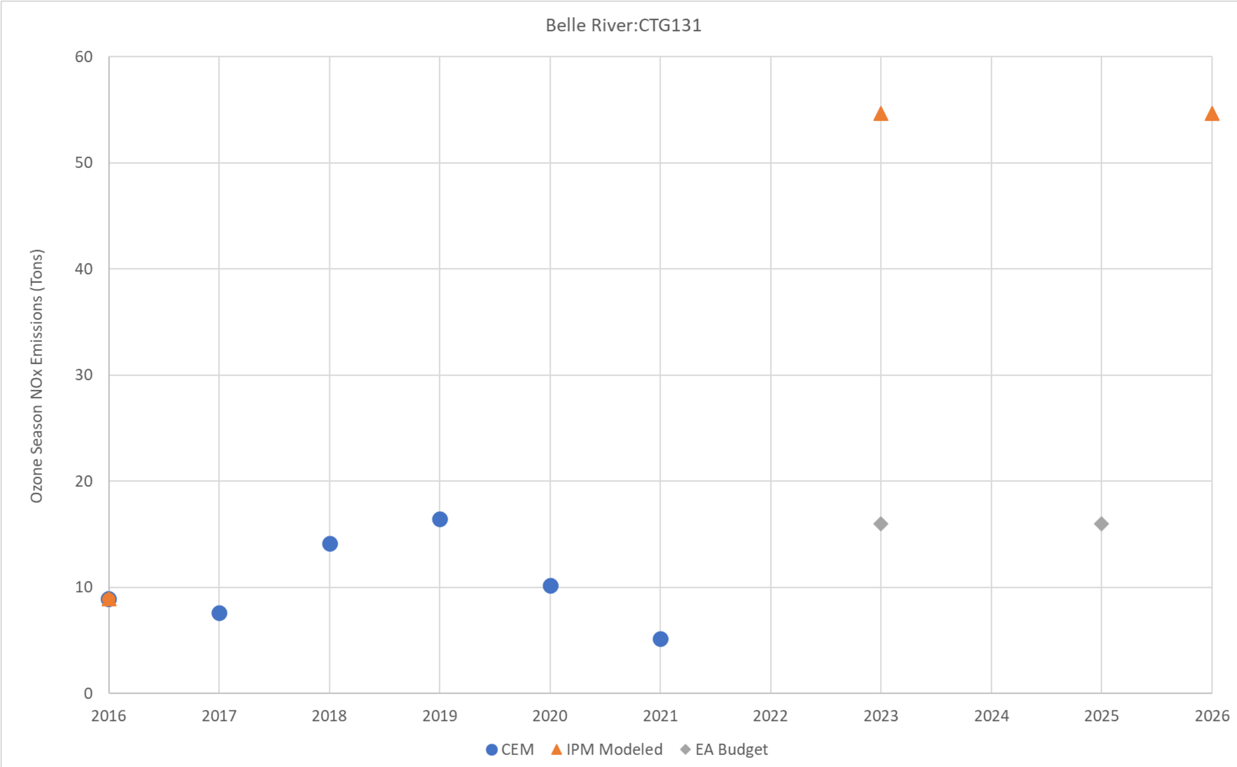

Figure 12. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Belle River Unit CTG131.

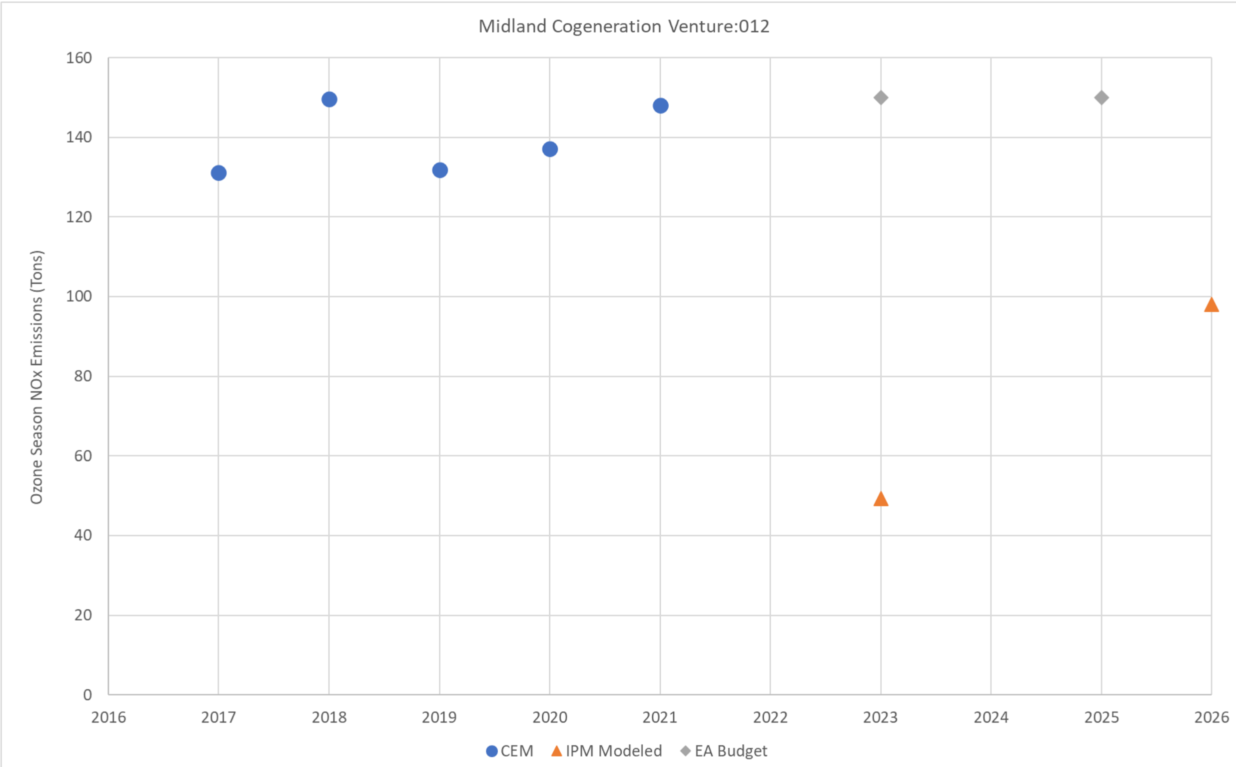

Figure 13. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Midland Cogeneration Venture Unit 012.

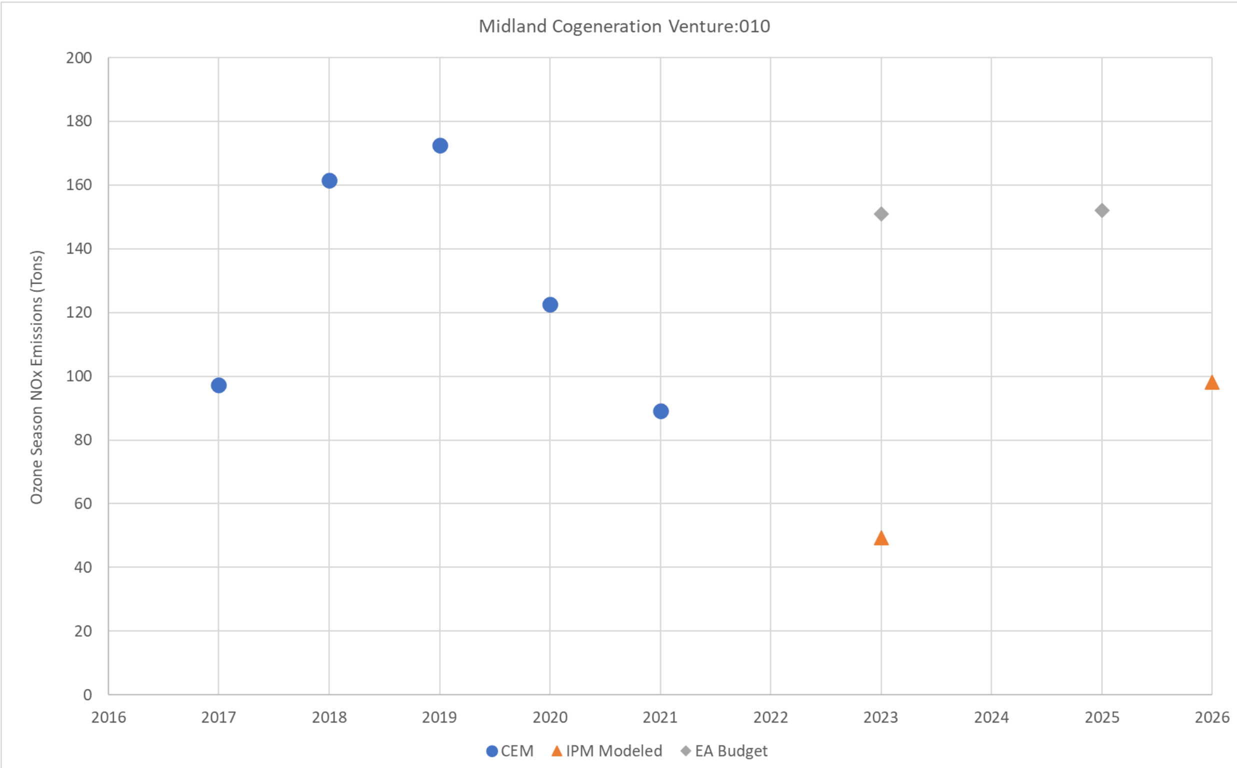

Figure 14. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Midland Cogeneration Venture Unit 010.

Minnesota

IPM projected emissions from the top seven units in Minnesota, that make up 99% of the ozone season NOx emissions in the portion of the 2023 projection comprised from CEM-reporting sources and ultimately assigned allocations in Step 3, are in aggregate 20% higher than the maximum year monitored emissions reported between 2017-2021. Table 3 presents this information for these seven units.

As the most extreme example, EPA's IPM-modeled ozone season NOx emissions in the 2023 base case were 3.6 times greater in magnitude at the Hibbard Energy Center, unit 4, than the maximum historical ozone season emissions from the 2017 – 2021 period.

Figure 15 through Figure 21 present this information for each of the units listed in Table 3. Blue dots represent the historical ozone season NOx emissions from CEM-reported data (orange dot represents 2016 CEM also modeled by EPA), orange triangles represent the 2023 and 2026 IPM base case projected emissions, and grey diamonds represent the FIP published allowance allocations.

Except for Boswell Unit 4 (Figure 3), all represented units have IPM-modeled 2023 ozone season NOx emissions exceeding the maximum historical CEM-based NOx emissions from 2017-2021 (i.e., orange triangles are higher than blue circles).

ALPINE GEOPHYSICS

	Ozone Season NOx Emissions (Tons)										
	CEM-Based										
Facility: Unit	2016	2017	2018	2019	2020	2021	Max (2017-2021)	EPA Allowance Allocation 2023	IPM-Generated 2023	% of Modeled Emissions (Step 1/2) Compared to Budget Emissions (Step 3)	% of Modeled Emissions (Step 1/2) Compared to Max Historical CEM
Allen S King:1	574	606	527	439	357	389	606	554	739	133%	122%
Boswell Energy Center:3	309	298	292	119	196	314	314	314	336	107%	107%
Boswell Energy Center:4	1,123	1,030	1,029	819	567	635	1,030	920	990	108%	96%
Hibbard Energy Center:3	93	123	108	86	51	68	123	33	307	929%	249%
Hibbard Energy Center:4	94	56	69	87	77	72	87	25	315	1259%	361%
Sherburne County:1	1,341	1,267	874	1,098	892	888	1,267	815	1,482	182%	117%
Sherburne County:3	1,477	986	1,420	1,148	894	1,013	1,420	991	1,656	167%	117%
Total							**4,847**	**3,652**	**5,825**	**160%**	**120%**

Table 3. Historical CEM-based ozone season NOx emissions, EPA's EA-based allowance allocation, EPA's IPM generated 2023 emissions, and percentage comparison for select Minnesota units.

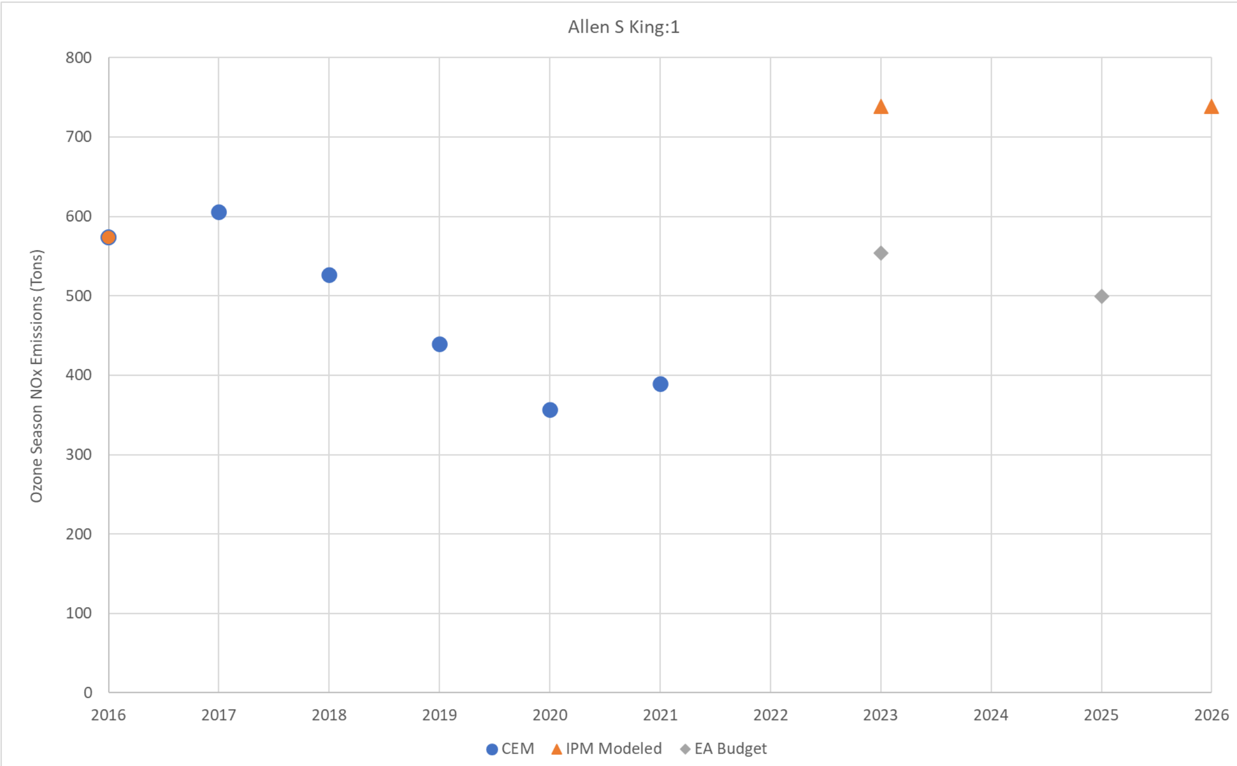

Figure 15. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Allen S King unit 1.

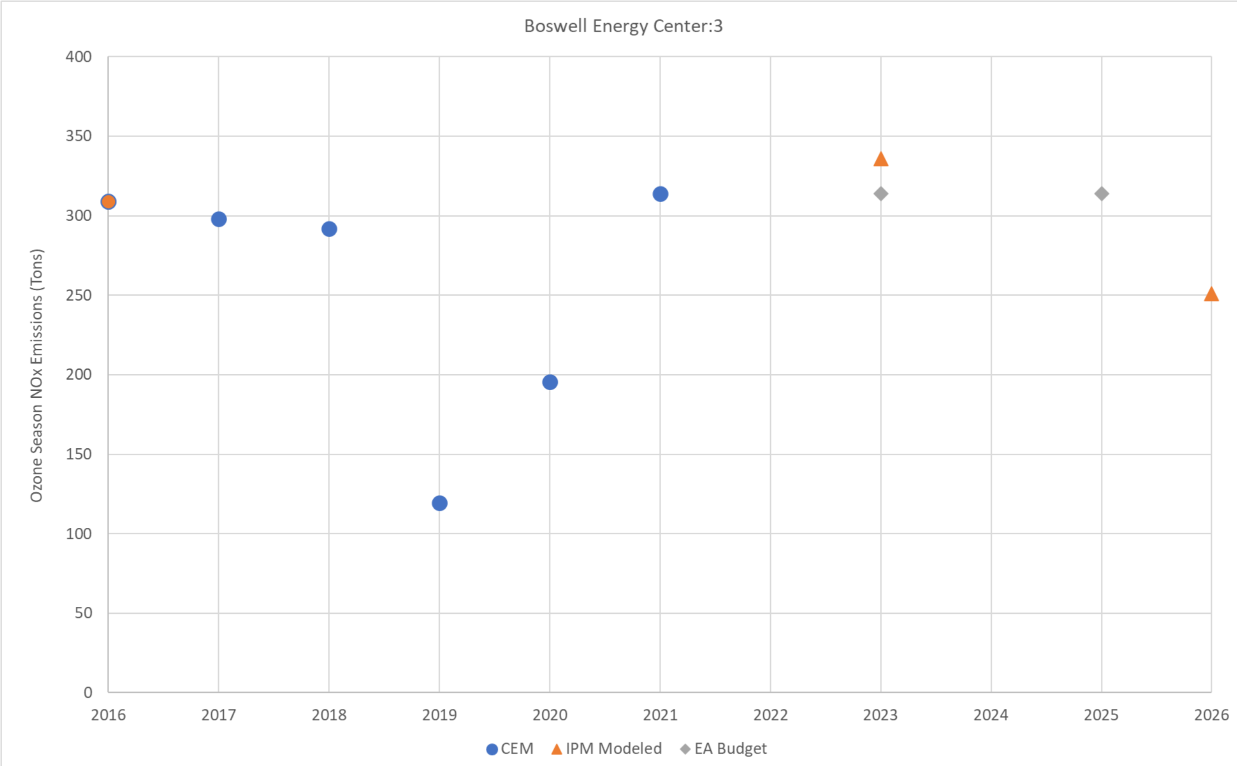

Figure 16. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Boswell Energy Center unit 3.

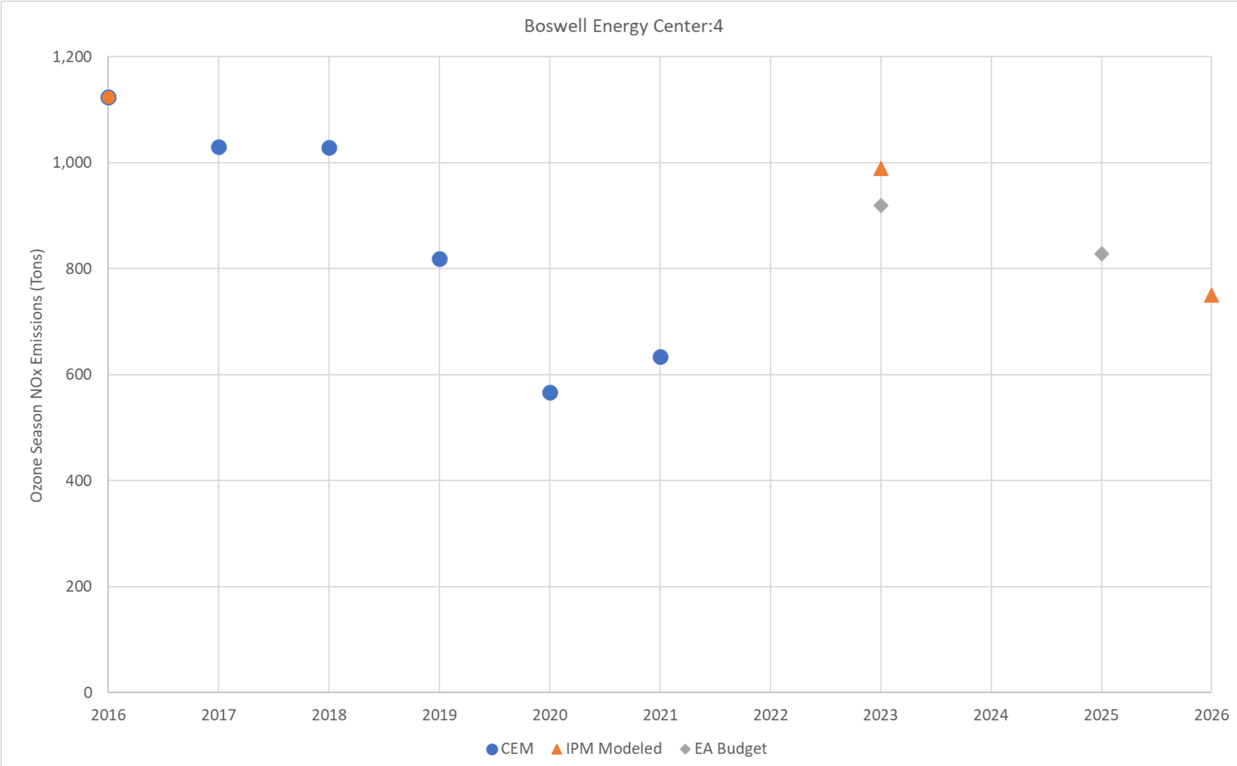

Figure 17. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Boswell Energy Center unit 3.

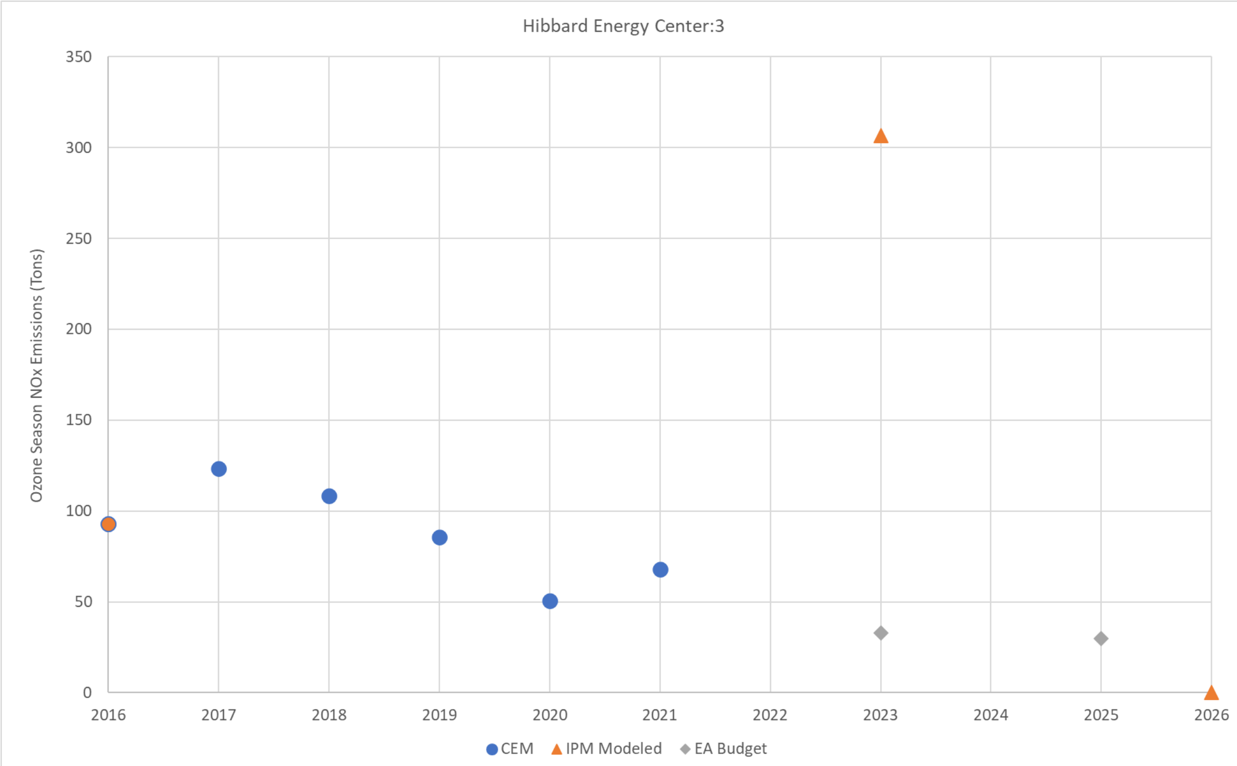

Figure 18. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Hibbard Energy Center unit 3.

ALPINE GEOPHYSICS

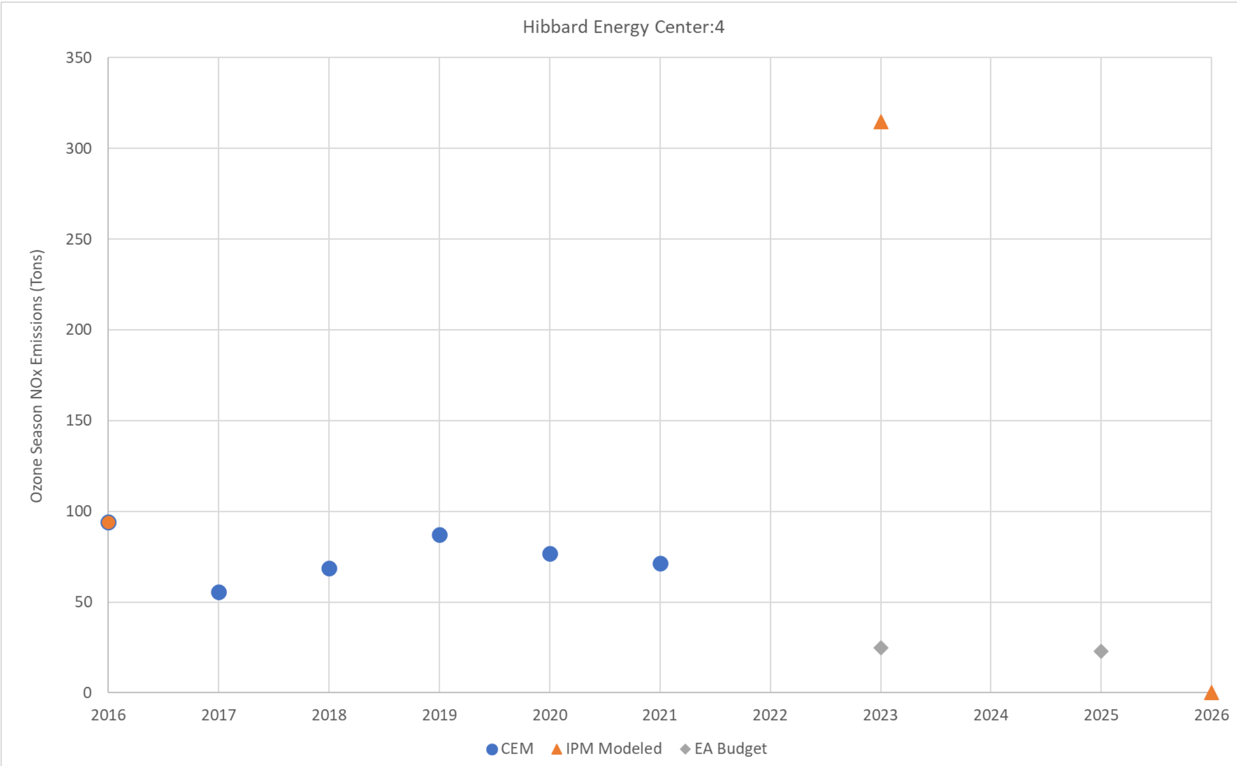

Figure 19. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Hibbard Energy Center unit 4.

ALPINE GEOPHYSICS

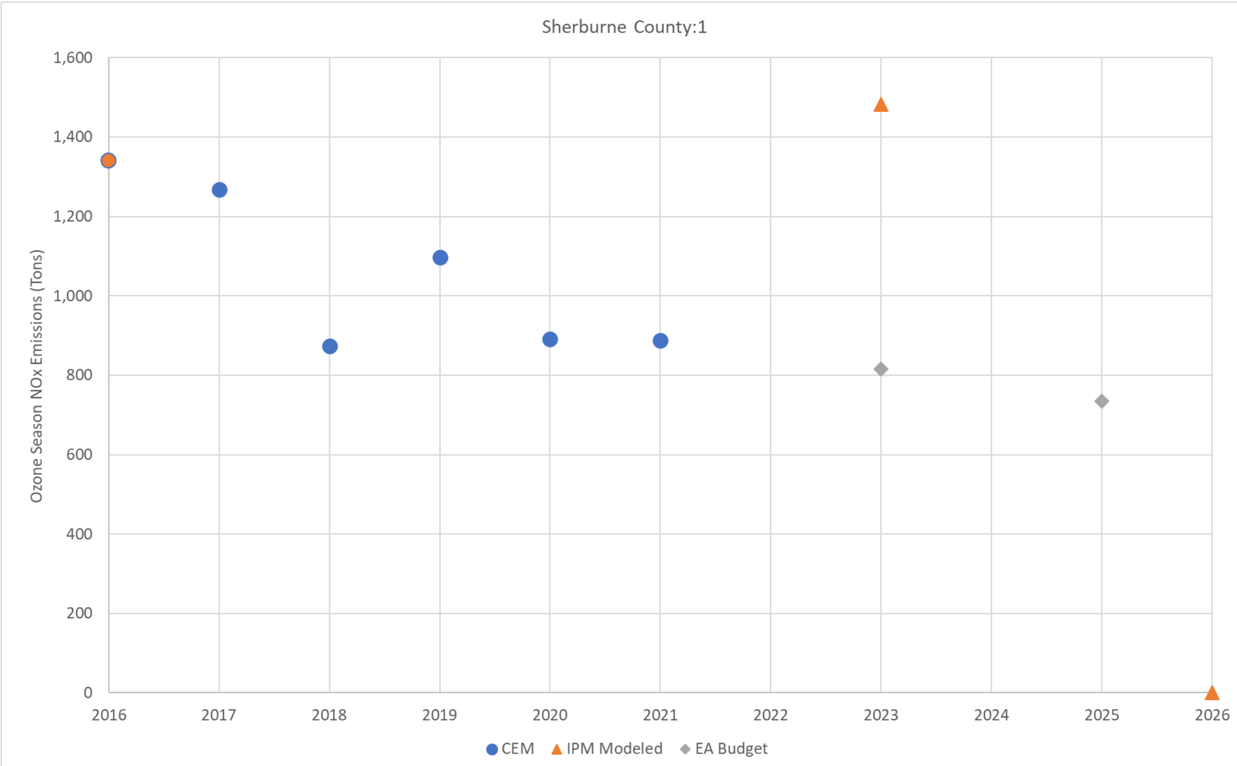

Figure 20. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Sherburne County unit 1.

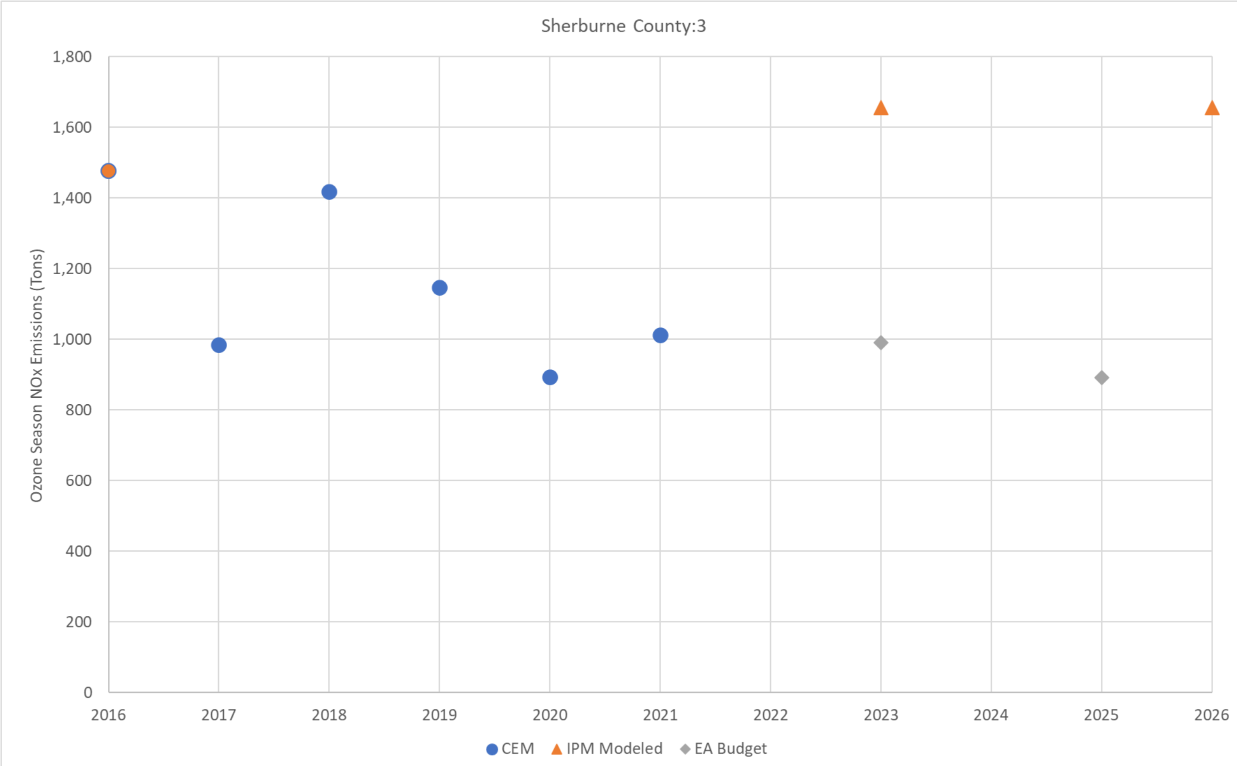

Figure 21. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at the Sherburne County unit 3.

Texas

IPM projected emissions from the top 2023 base case units in Texas are collectively 37% higher than the maximum year monitored emissions reported between 2017-2021 for these same units. Table 4 presents this information for these units in the state.

Figure 22 through Figure 28 present this information for multiple units listed in Table 4. Blue dots represent the historical ozone season NOx emissions from CEM-reported data (orange dot represents 2016 CEM also modeled by EPA), orange triangles represent the 2023 and 2026 IPM base case projected emissions, and grey diamonds represent the FIP published allowance allocations.

ALPINE GEOPHYSICS

	Ozone Season NOx Emissions (Tons)										
	CEM-Based										
Facility: Unit	2016	2017	2018	2019	2020	2021	Max (2017-2021)	EPA Allowance Allocation 2023	IPM-Generated 2023	% of Modeled Emissions (Step 1/2) Compared to Budget Emissions (Step 3)	% of Modeled Emissions (Step 1/2) Compared to Max Historical CEM
Limestone:LIM2	2,369	2,373	2,015	1,795	1,384	1,480	2,373	1,195	2,278	191%	96%
Martin Lake:2	1,523	1,631	1,390	1,394	1,460	1,264	1,631	1,011	2,153	213%	132%
Martin Lake:1	1,783	1,714	1,699	1,170	1,583	1,628	1,714	1,154	2,148	186%	125%
Limestone:LIM1	1,854	1,850	1,709	1,697	1,200	627	1,850	1,107	2,071	187%	112%
Martin Lake:3	1,433	1,377	1,709	1,339	1,326	1,585	1,709	1,133	2,005	177%	117%
Tolk Station:171B	917	840	647	494	530	662	840	496	1,396	281%	166%
Coleto Creek:1	1,174	1,299	1,263	1,049	1,049	1,438	1,438	976	1,383	142%	96%
Tolk Station:172B	1,056	943	611	706	584	1,008	1,008	568	1,361	240%	135%
V H Braunig:CGT6	1	1	1	1	1	1	1	1	1,236	123594%	91213%
Winchester Power Park:3	0	0	0	0	0	0	0	0	1,074	#NA	219593%
Oak Grove:2	998	1,068	1,080	1,059	1,008	1,099	1,099	1,099	1,045	95%	95%
Oak Grove:1	994	1,125	1,100	1,111	1,081	1,113	1,125	1,125	1,036	92%	92%
Winchester Power Park:2	0	1	0	0	0	0	1	1	1,022	102179%	164539%

Table 4. Historical CEM-based ozone season NOx emissions, EPA's EA-based allowance allocation, EPA's IPM generated 2023 emissions, and percentage comparison for top 2023 modeled Texas units.

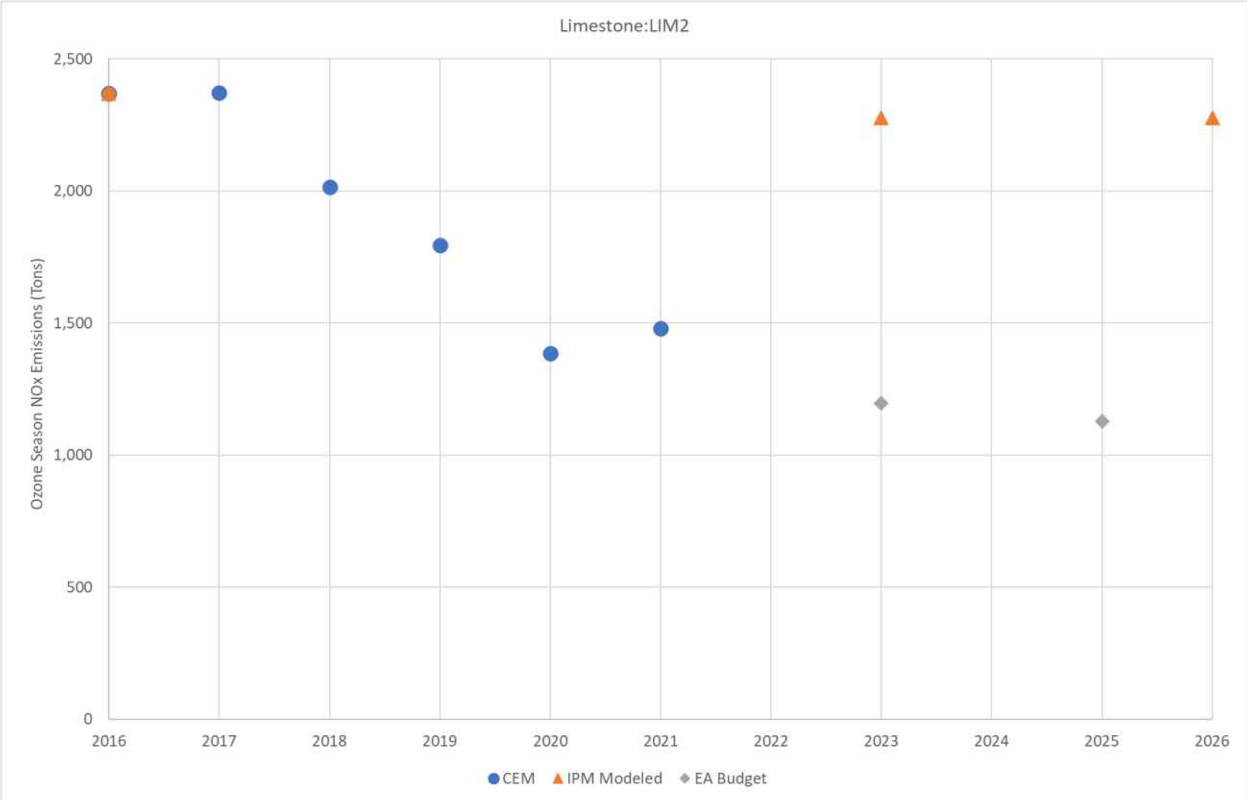

Figure 22. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Limestone Unit 2.

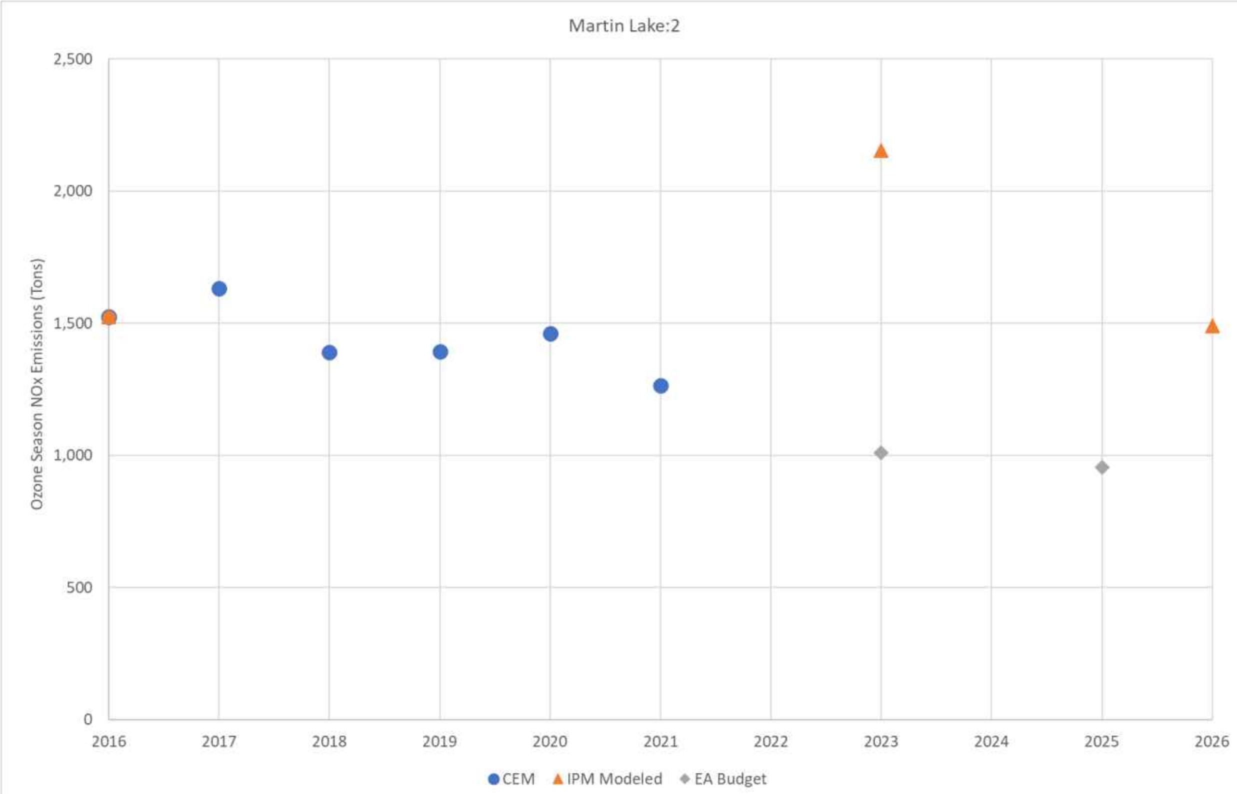

Figure 23. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Martin Lake Unit 2.

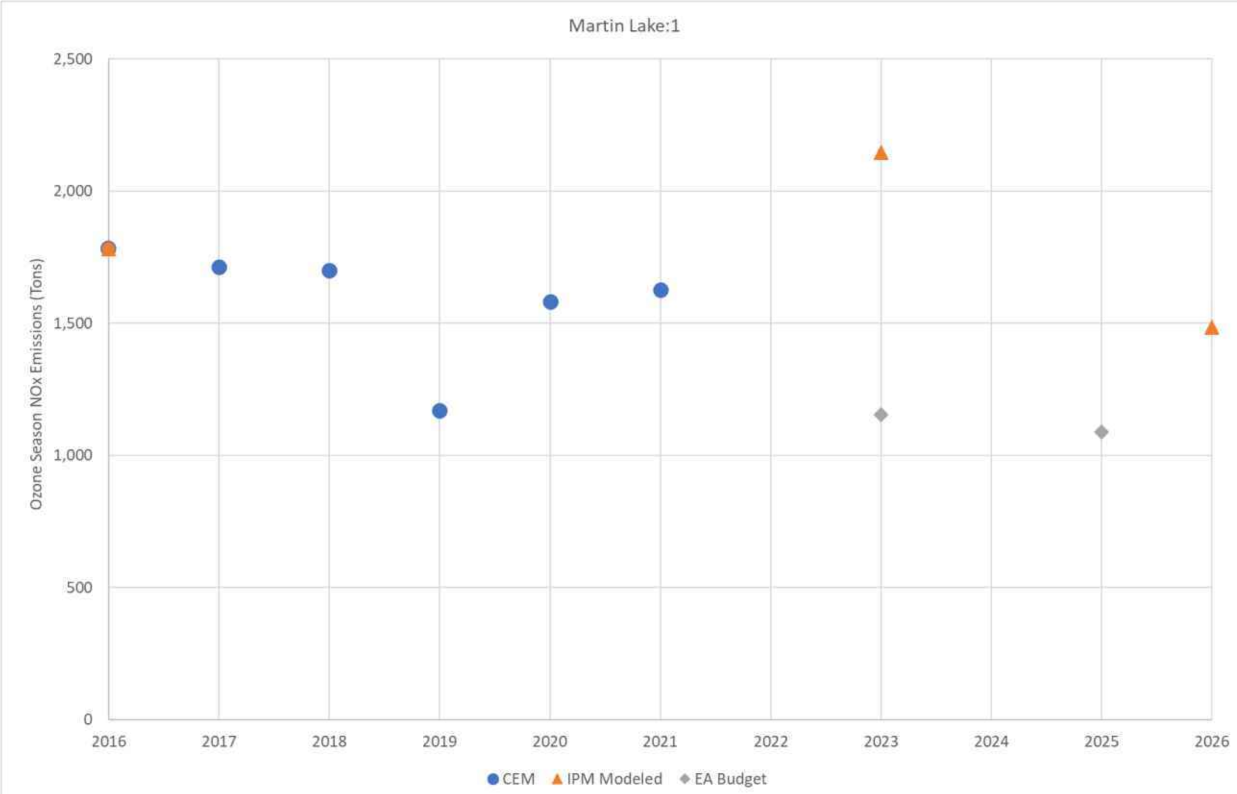

Figure 24. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Martin Lake Unit 1.

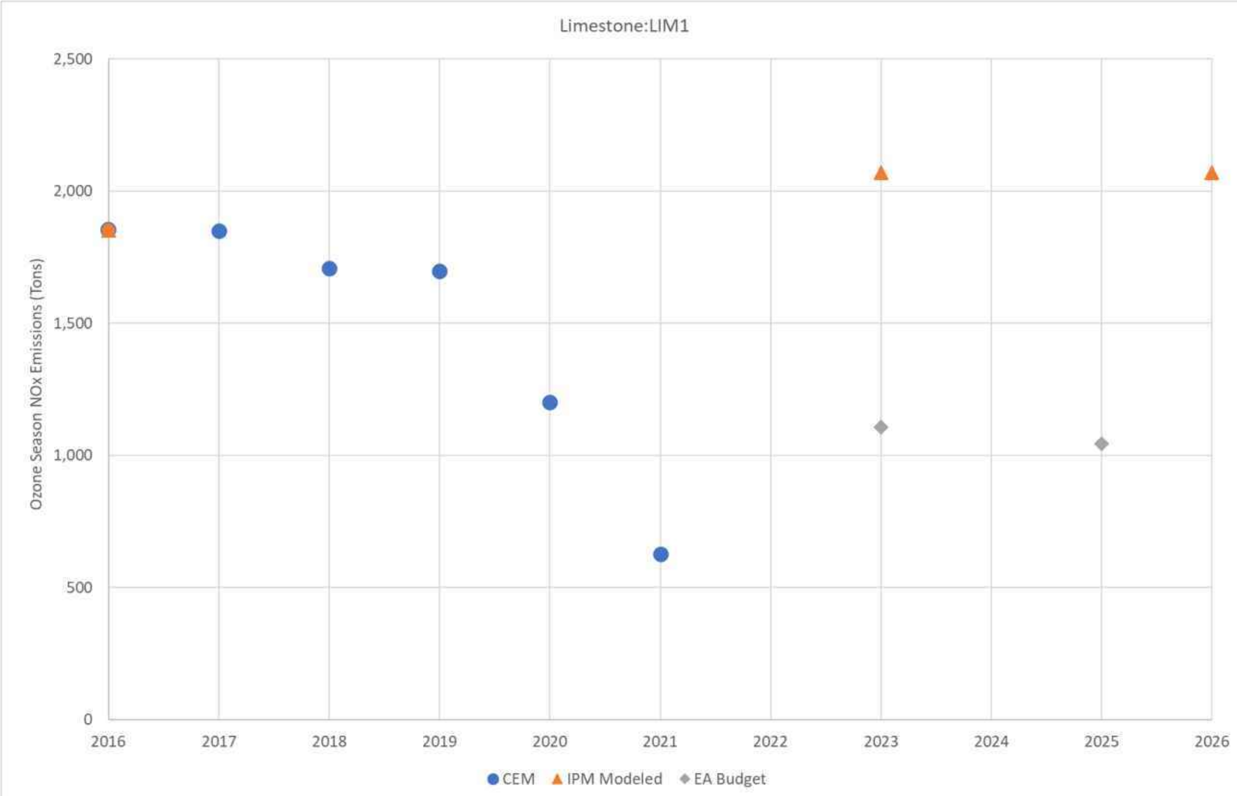

Figure 25. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Limestone Unit LIM1.

ALPINE GEOPHYSICS

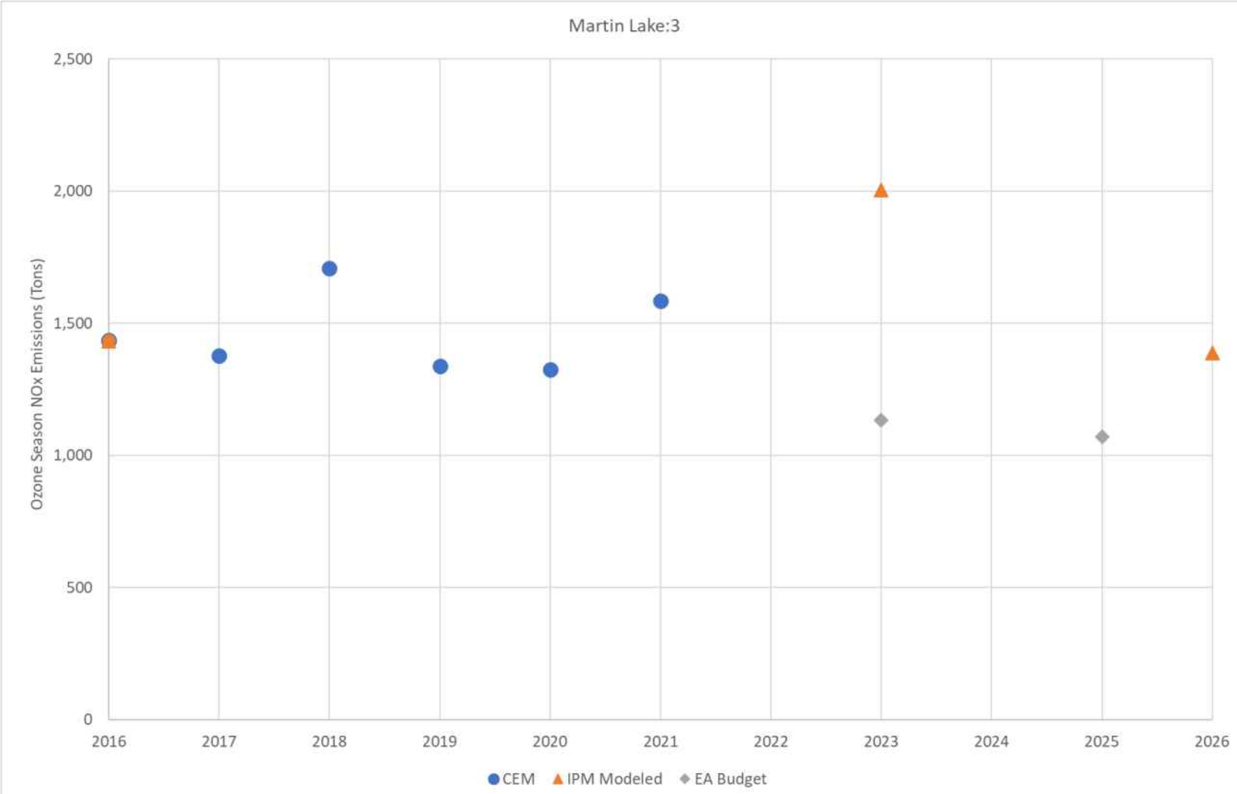

Figure 26. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Martin Lake Unit 3.

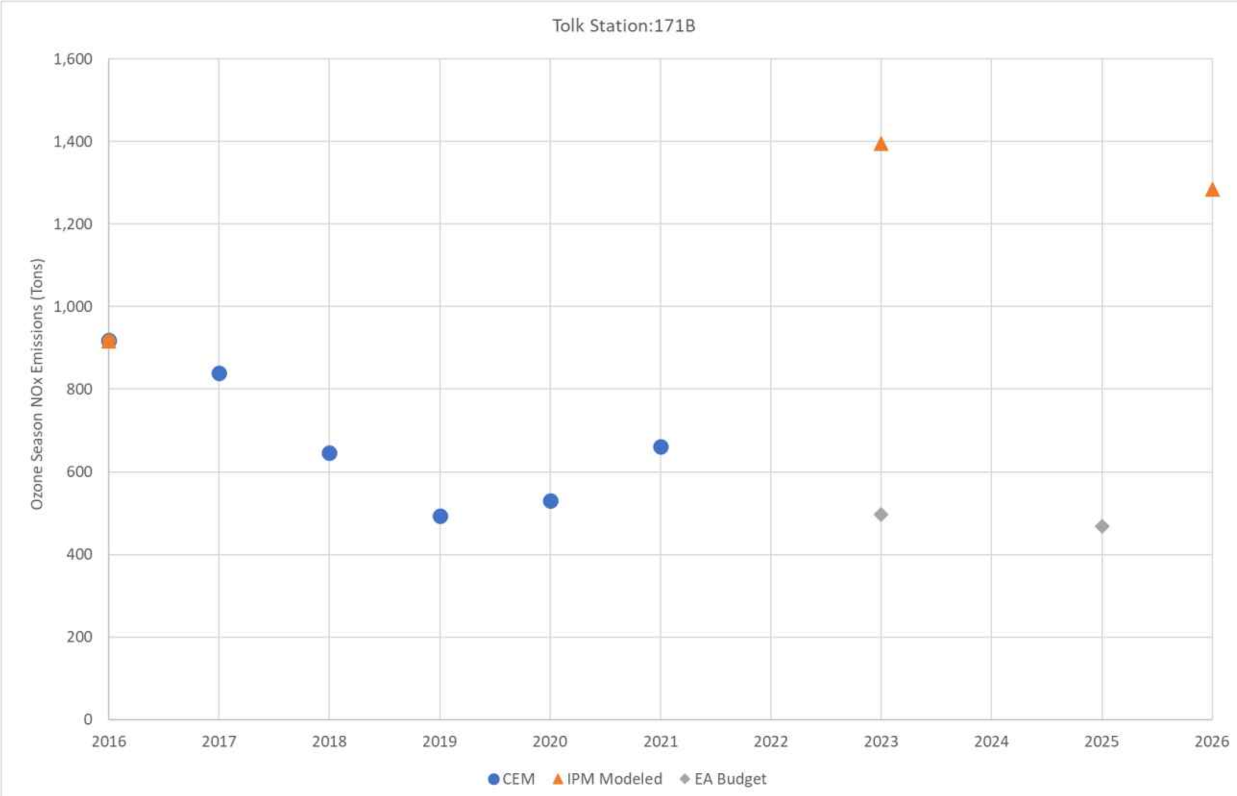

Figure 27. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Tolk Station Unit 171B.

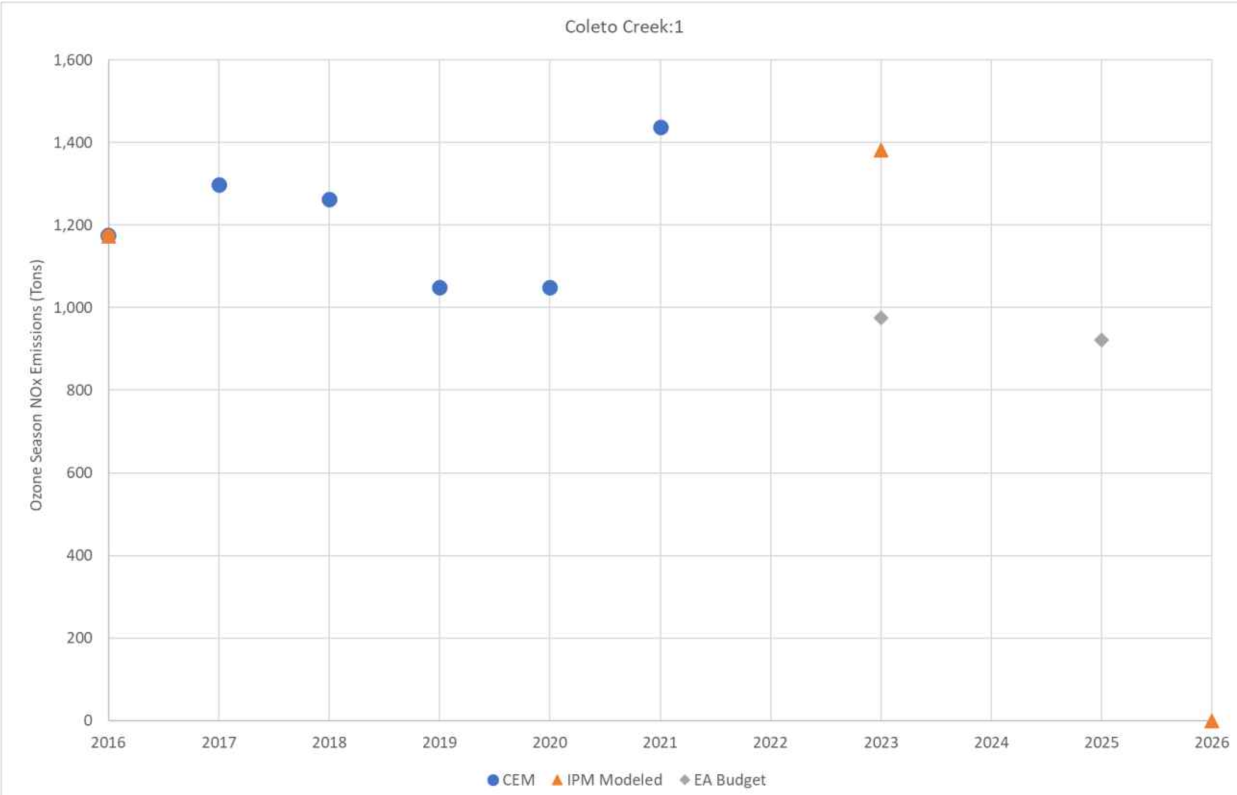

Figure 28. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Coleto Creek Unit 1.

Wisconsin

IPM projected emissions from the top 2023 base case units in Wisconsin are collectively 4% times lower than the maximum year monitored emissions reported between 2017-2021 for these same units. Table 5 presents this information for these units in the state.

Figure 29 through Figure 35 present this information for multiple units listed in Table 5. Historical CEM-based ozone season NOx emissions, EPA's EA-based allowance allocation, EPA's IPM generated 2023 emissions, and percentage comparison for top 2023 modeled Wisconsin units.. Blue dots represent the historical ozone season NOx emissions from CEM-reported data (orange dot represents 2016 CEM also modeled by EPA), orange triangles represent the 2023 and 2026 IPM base case projected emissions, and grey diamonds represent the FIP published allowance allocations.

ALPINE GEOPHYSICS

	Ozone Season NOx Emissions (Tons)										
	CEM-Based										
Facility: Unit	2016	2017	2018	2019	2020	2021	Max (2017-2021)	EPA Allowance Allocation 2023	IPM-Generated 2023	% of Modeled Emissions (Step 1/2) Compared to Budget Emissions (Step 3)	% of Modeled Emissions (Step 1/2) Compared to Max Historical CEM
Columbia:1	1057	1103	1076	953	908	1025	1,103	642	1107	172%	100%
Elm Road Generating Station:2	530	470	611	492	543	675	675	675	605	90%	90%
Valley (WEPCO):1	19	24	16	26	30	17	30	30	590	1965%	1956%
Columbia:2	966	1092	235	335	258	549	1,092	632	487	77%	45%
J P Madgett:B1	422	281	341	290	283	334	341	321	424	132%	124%
Bay Front:1	66	78	67	74	58	65	78	25	179	714%	229%
Manitowoc:8	11	4	4	1	3	6	6	4	80	2003%	1350%
Weston:4	333	367	310	370	401	356	401	401	73	18%	18%
Marshfield Utilities Combustion Turbine:1A	1	0	0	0	0	2	2	1	54	5395%	3256%

Table 5. Historical CEM-based ozone season NOx emissions, EPA's EA-based allowance allocation, EPA's IPM generated 2023 emissions, and percentage comparison for top 2023 modeled Wisconsin units.

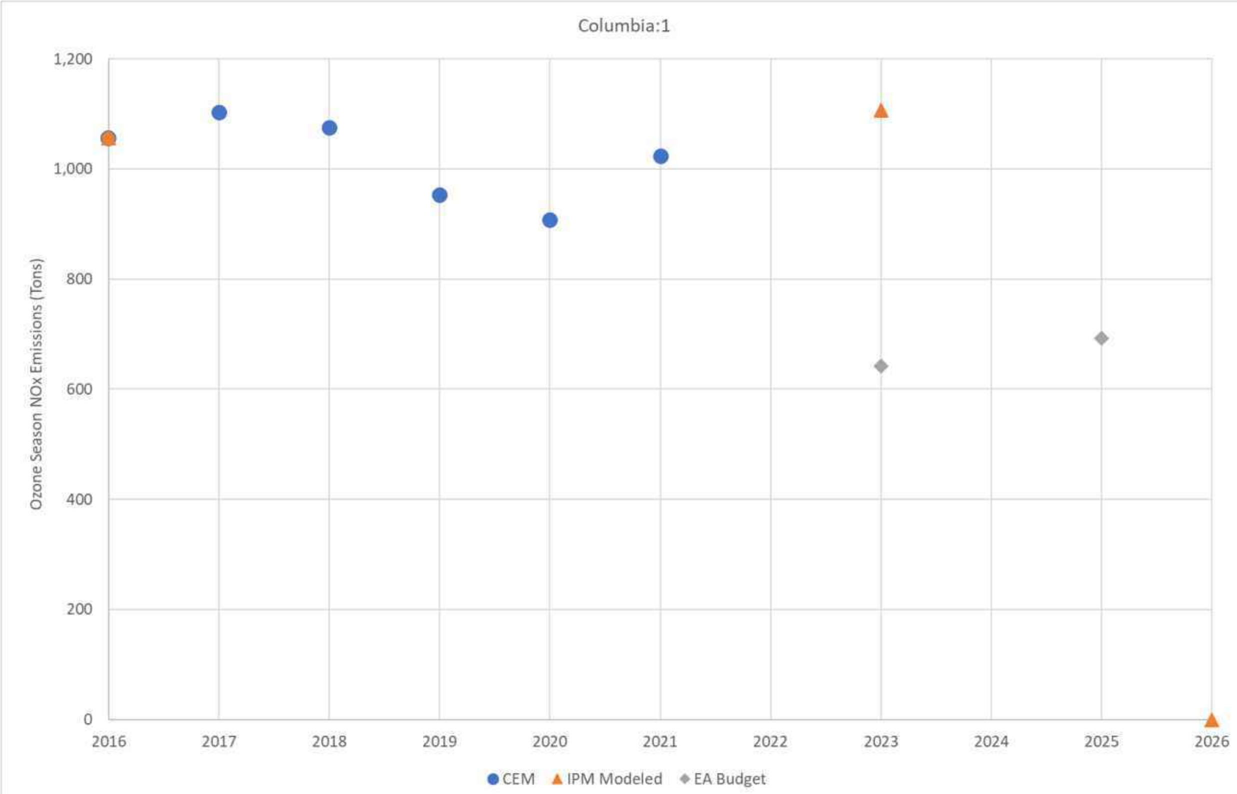

Figure 29. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Columbia Unit 1.

ALPINE GEOPHYSICS

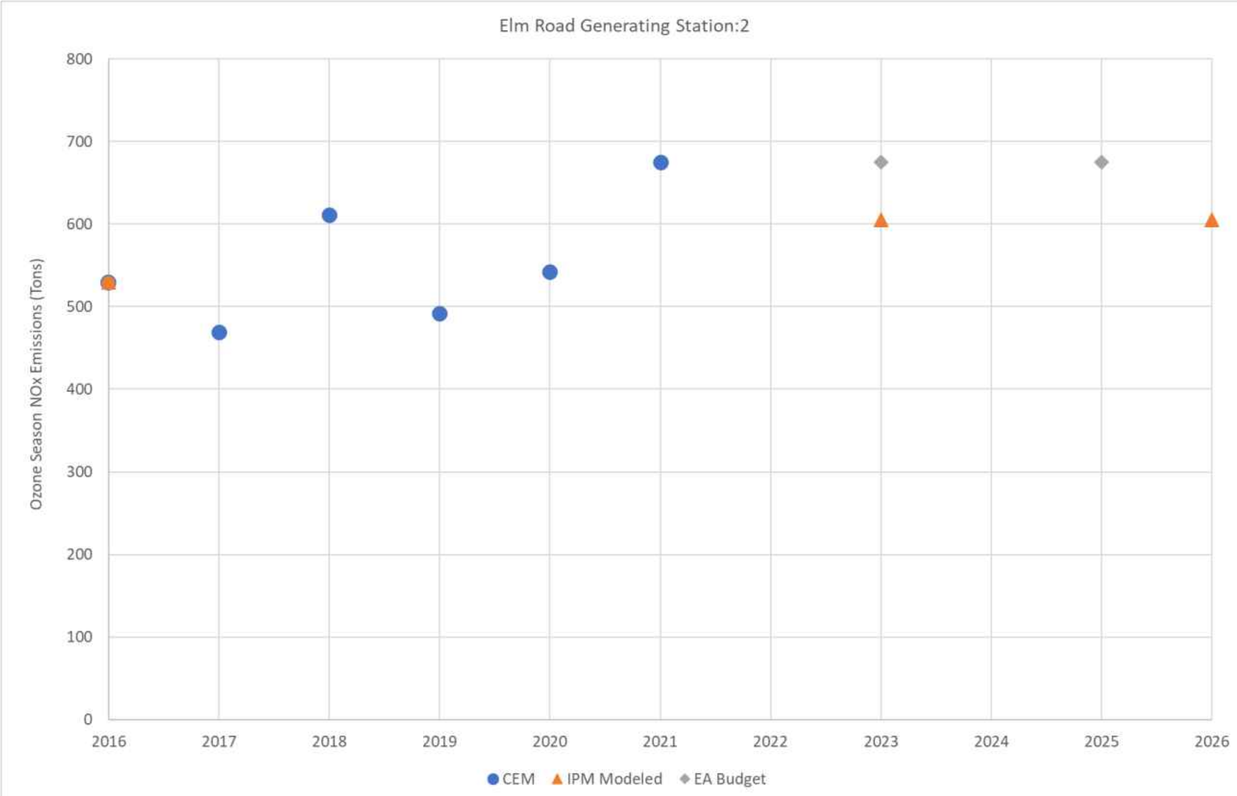

Figure 30. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Elm Road Generating Station Unit 2.

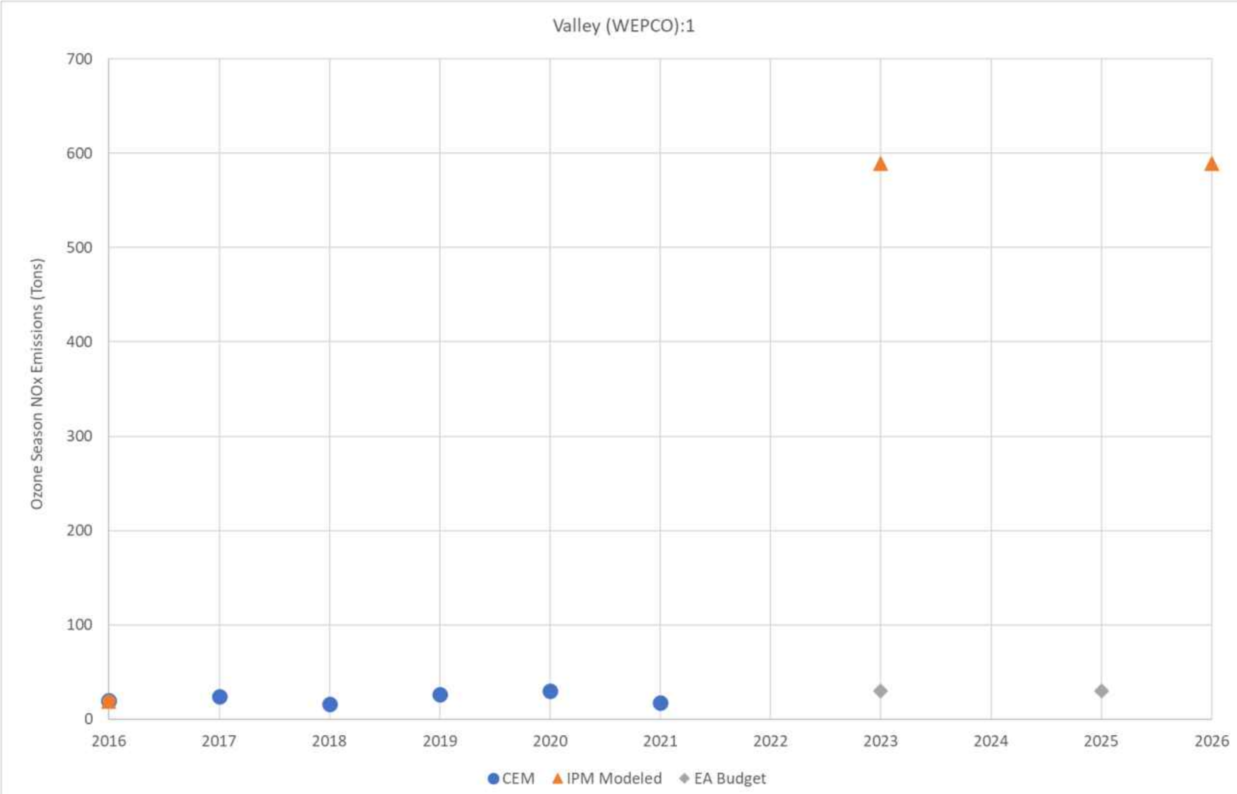

Figure 31. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Valley (WEPCO) Unit 1.

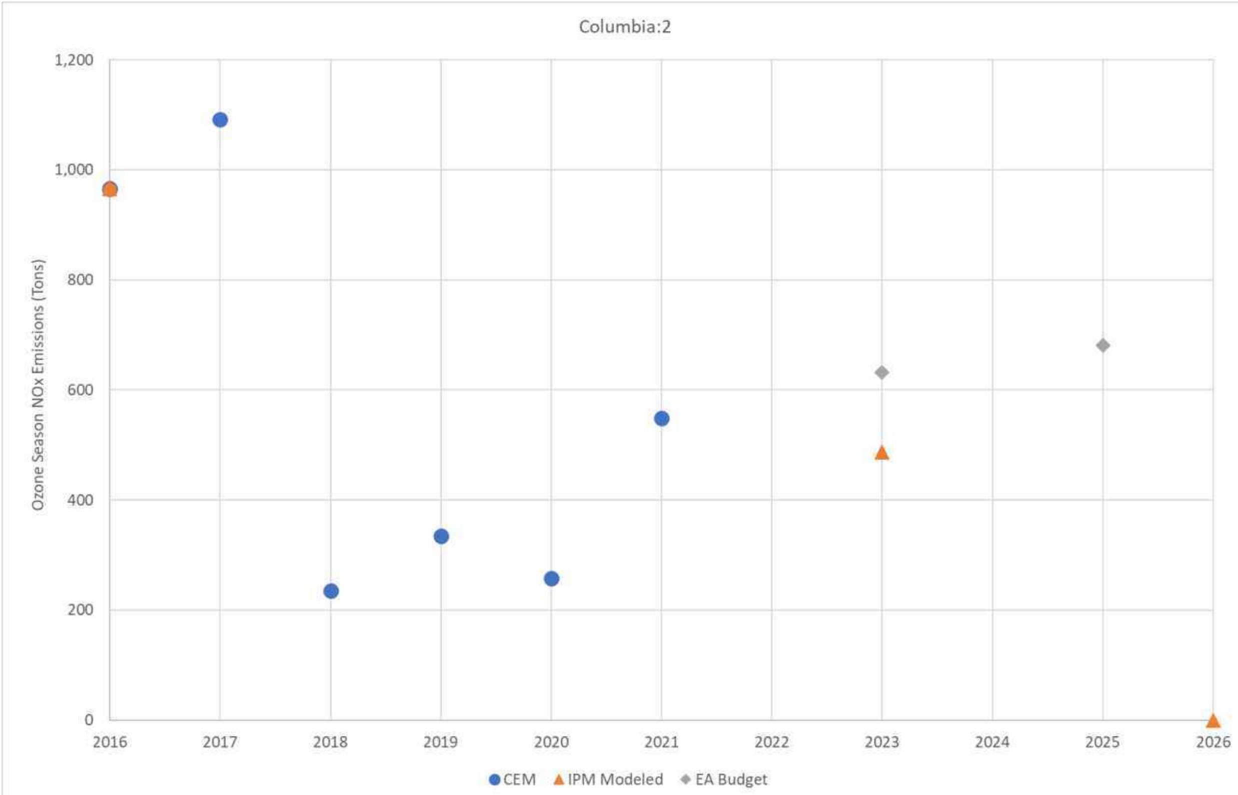

Figure 32. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Columbia Unit 2.

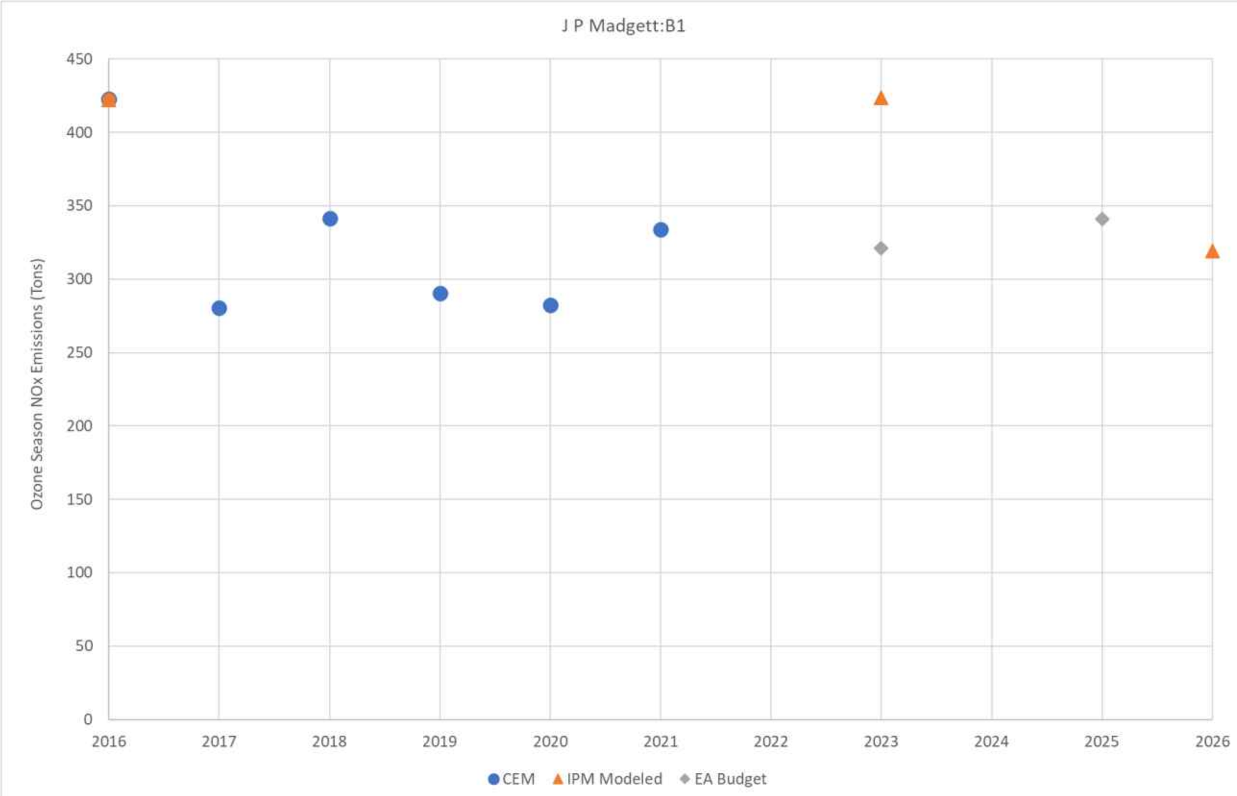

Figure 33. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at J P Madgett Unit B1.

ALPINE GEOPHYSICS

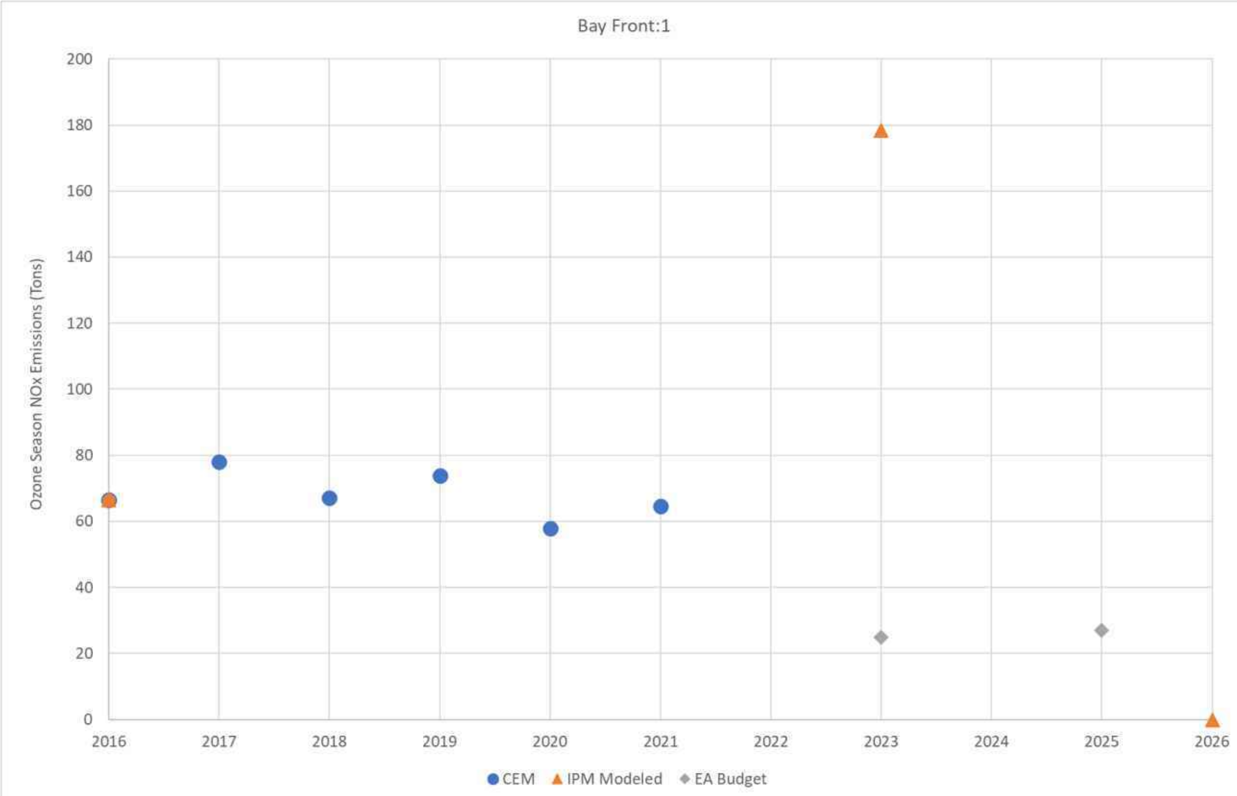

Figure 34. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Bay Front Unit 1.

ALPINE GEOPHYSICS

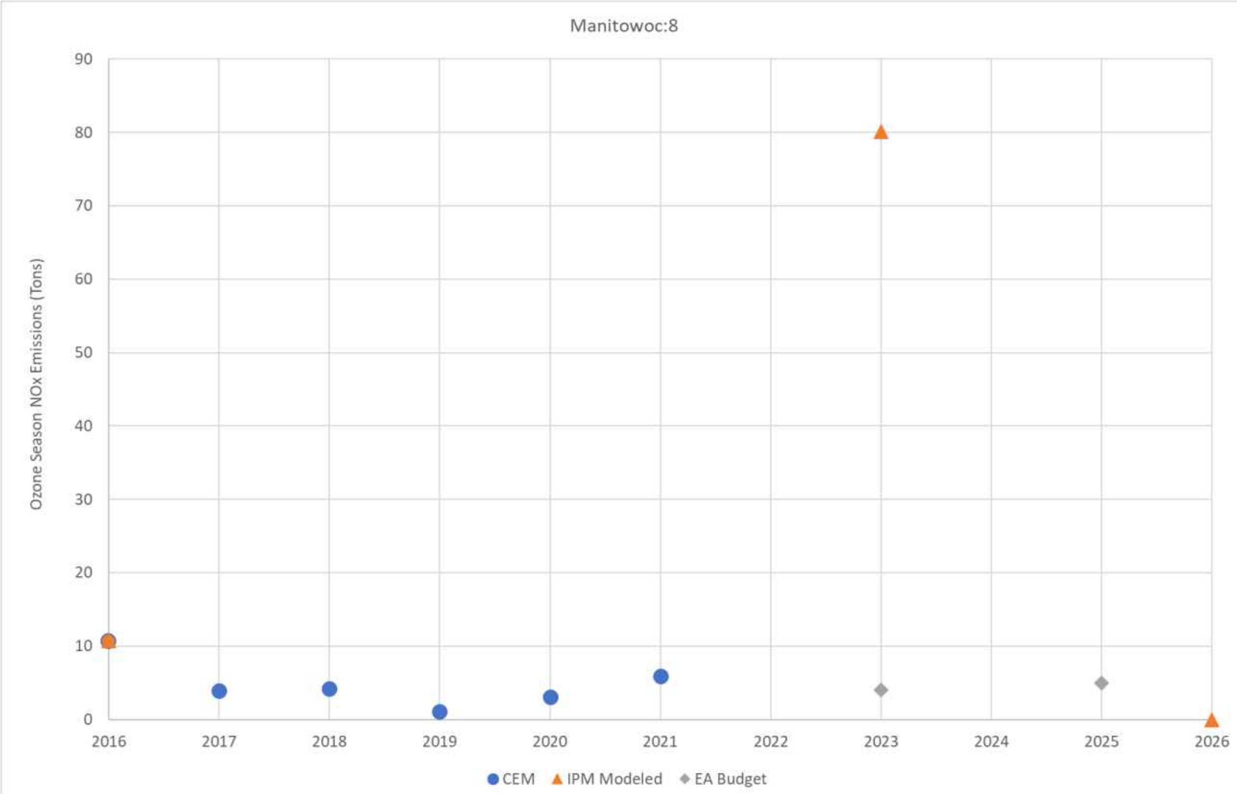

Figure 35. Historical and projected ozone season NOx emissions from CEM, IPM, and engineering analytics calculations at Manitowoc Unit 8.

F. Observations

EPA failed to appropriately estimate 2023 base case emissions for multiple upwind EGU sources using IPM thereby compromising downwind concentrations and significant contribution calculations associated with these states. The agency should have used consistent data in each step of the process to ensure that calculations conducted were relevant to each other and provided certainty in direction and value. If EPA had properly characterized emissions at these facilities using historical operation trends (as it did in the Step 3 process), the Alsip monitor in Cook County, Illinois, with which Minnesota is linked, may have modeled in attainment of the 2015 ozone NAAQS, removing Minnesota from the FIP in Step 2 of the transport framework.

It is understood that allocations for these units (Step 3) may be lower because of EPA's estimated optimization of post-combustion controls on some of these sources and new source set aside reduction, yet there is no valid reason for the IPM-generated base case projection of many of these sources to have such significantly higher values for purposes of Step 1 and Step 2 in the transport framework. In our opinion, conservative estimates or not, individual unit-level emission over-estimation and a collective over-estimation of emissions for key units subject to control, potentially only because of this over-estimation, is technically negligent.

Except for presented units in Wisconsin, represented states have the majority of IPM-modeled 2023 ozone season NOx emissions exceeding the maximum historical CEM-based NOx emissions from 2017-2021. As these modeled values were the ozone season NOx emissions used for these sources to represent upwind state contribution to downwind design values and significant contribution calculations, it is safe to deduce that the higher the modeled emission values, the higher the downwind concentrations at receptors like the Alsip monitor in Cook County, Illinois (170310001) and significant contribution calculations from upwind states to that monitor.

Furthermore, if the projected near-term unit-level emissions from IPM were more in line with recent historical CEM-based observations, particularly if the pattern observed at these sources hold for other sources, the projected maximum design value at the Alsip monitor may have been modeled as attainment, breaking the link between Minnesota and the receptor.

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit H

Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 Fed. Reg. 49,295 (July 31, 2023)

Dated: July 19, 2023.

Shira Perlmutter,

Register of Copyrights and Director of the U.S. Copyright Office.

Approved by:

Carla D. Hayden,

Librarian of Congress.

[FR Doc. 2023–15941 Filed 7–28–23; 8:45 am]

BILLING CODE 1410–30–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 52 and 97

[EPA–HQ–OAR–2021–0668; FRL–8670.2–03–OAR]

Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States

AGENCY: Environmental Protection Agency (EPA).

ACTION: Interim final rule; request for comment.

SUMMARY: The Environmental Protection Agency (EPA) is taking interim final action to stay, for emissions sources in Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas only, the effectiveness of the federal implementation plan (FIP) requirements established to address the obligations of these and other states to mitigate interstate air pollution with respect to the 2015 national ambient air quality standards (NAAQS) for ozone (the Good Neighbor Plan). The EPA is also revising certain other regulations to ensure that sources in these states will continue to be subject to previously established requirements to mitigate interstate air pollution with respect to other ozone NAAQS while the Good Neighbor Plan's requirements are stayed. These revisions will also ensure that the stay is limited to requirements for which the EPA does not currently have authority to implement a FIP pending judicial review. The stay and the associated revisions to other regulations are being issued in response to judicial orders that partially stay, pending judicial review, a separate, earlier EPA action which disapproved certain state implementation plan (SIP) revisions submitted by these and other states. Finally, for states for which the Good Neighbor Plan's requirements are not being stayed, the EPA is revising three near-term deadlines that are incorrect as published in the Good Neighbor Plan.

DATES: This interim final rule is effective on August 4, 2023. Comments on this rule must be received on or before August 30, 2023.

ADDRESSES: You may send comments, identified by Docket ID No. EPA–HQ–OAR–2021–0668, by any of the following methods:

- *Federal eRulemaking portal: https://www.regulations.gov* (our preferred method). Follow the online instructions for submitting comments.
- *Mail:* U.S. Environmental Protection Agency, EPA Docket Center, Air and Radiation Docket, Mail Code 28221T, 1200 Pennsylvania Avenue NW, Washington, DC 20460.
- *Hand delivery or courier:* EPA Docket Center, WJC West Building, Room 3334, 1301 Constitution Avenue NW, Washington, DC 20004. The Docket Center's hours of operations are 8:30 a.m.–4:30 p.m., Monday–Friday (except federal holidays).

Comments received may be posted without change to *https://www.regulations.gov,* including any personal information provided. For detailed instructions on sending comments, see the "Public Participation" heading of the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: David Lifland, Clean Air Markets Division, Office of Atmospheric Protection, Office of Air and Radiation, U.S. Environmental Protection Agency, Mail Code 6204A, 1200 Pennsylvania Avenue NW, Washington, DC 20460; telephone: 202–343–9151; email: *lifland.david@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General

A. Public Participation

Submit your written comments, identified by Docket ID No. EPA–HQ–OAR–2021–0668, at *https://www.regulations.gov* (our preferred method), or by the other methods identified in the **ADDRESSES** section. Once submitted, comments cannot be edited or removed from the docket. The EPA may publish any comment received to its public docket. Do not submit to the EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI), Proprietary Business Information (PBI), or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI, PBI, or multimedia submissions; and general guidance on making effective comments.

B. Potentially Affected Entities

This action revises on an interim basis the Good Neighbor Plan, which applies to electricity generating units (EGUs) and non-EGU industrial sources. This action also revises other allowance trading program regulations that apply to EGUs but not to non-EGU industrial sources. The affected emissions sources are generally in the following industry groups:

Industry group	North American Industry Classification System (NAICS) code
Fossil Fuel Electric Power Generation	221112
Pipeline Transportation of Natural Gas	4862
Cement and Concrete Product Manufacturing	3273
Iron and Steel Mills and Ferroalloy Manufacturing	3311
Glass and Glass Product Manufacturing	3272
Basic Chemical Manufacturing	3251
Petroleum and Coal Products Manufacturing	3241
Pulp, Paper, and Paperboard Mills	3221
Metal Ore Mining	2122
Solid Waste Combustors and Incinerators	562213

The Good Neighbor Plan applies to emissions sources in Alabama, Arkansas, California, Illinois, Indiana, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, Nevada, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Texas, Utah, Virginia, West Virginia, and Wisconsin. The portions of this action staying the Good Neighbor Plan's requirements and revising other allowance trading program regulations apply to sources in Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas. The portions of this action revising certain near-term deadlines under the Good Neighbor Plan apply to emissions sources in the other listed states, for which the Good Neighbor Plan's requirements are not being stayed.

The information provided in this section on potentially affected entities is not intended to be exhaustive. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

C. Statutory Authority

Statutory authority to issue the amendments finalized in this action is provided by the same Clean Air Act (CAA) provisions that provided authority to issue the regulations being amended: CAA section 110(a) and (c), 42 U.S.C. 7410(a) and (c) (SIP and FIP requirements, including requirements for mitigation of interstate air pollution), and CAA section 301, 42 U.S.C. 7601 (general rulemaking authority). Statutory authority for the rulemaking procedures followed in this action is provided by Administrative Procedure Act (APA) section 553, 5 U.S.C. 553.

II. Regulatory Revisions

A. Response to Stay Orders

1. Background and Summary

CAA section 110(a)(2)(D)(i)(I), also known as the ''good neighbor'' provision, requires each state's SIP to include provisions sufficient to ''prohibit[ ], consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any [NAAQS].'' The EPA often refers to the emissions reduction requirements under this provision as ''good neighbor obligations'' and submissions addressing these requirements as ''good neighbor SIPs.''

CAA section 110(c)(1) requires the EPA Administrator to promulgate a FIP at any time within two years after the Administrator: (i) finds that a state has failed to make a required SIP submission; (ii) finds a SIP submission to be incomplete pursuant to CAA section 110(k)(1)(C); or (iii) disapproves a SIP submission. This obligation applies unless the state corrects the deficiency through a SIP revision that the Administrator approves before the FIP is promulgated.

On February 13, 2023, the EPA published a final action fully or partially disapproving good neighbor SIPs submitted by 21 states with respect to the 2015 ozone NAAQS (the SIP Disapproval action).[1] Consistent with the requirements of CAA section 110(c)(1), following the SIP Disapproval action, on March 15, 2023, the EPA Administrator signed a separate final action promulgating a FIP, which is referred to here as the ''Good Neighbor Plan'' or the ''Rule.''[2] The Good Neighbor Plan requires EGUs and non-EGU industrial sources in the 21 states whose good neighbor SIPs the EPA had disapproved in the SIP Disapproval action (as well as two other states for which the EPA had previously made findings of failure to submit good neighbor SIPs) to reduce their emissions of nitrogen oxides (NO_X) during the May-September ''ozone season'' to address the states' good neighbor obligations with respect to the 2015 ozone NAAQS.[3] The Good Neighbor Plan was published in the **Federal Register** on June 5, 2023, and its requirements will be phased in over several years starting on the Rule's August 4, 2023, effective date.

To implement the required emissions reductions from EGUs, the Good Neighbor Plan uses an emissions allowance trading program. The EPA has previously established three successive allowance trading programs for EGUs' seasonal NO_X emissions to address states' good neighbor obligations with respect to the 1997 and 2008 ozone NAAQS—referred to here as the CSAPR NO_X Ozone Season ''Group 1,'' ''Group 2,'' and ''Group 3'' trading programs—in the Cross-State Air Pollution Rule (CSAPR),[4] the CSAPR Update,[5] and the Revised CSAPR Update,[6] respectively. The Good Neighbor Plan does not establish a new emissions trading program, but instead modifies the Group 3 trading program initially established in the Revised CSAPR Update and expands the program to apply to EGUs in the additional states included in the Good Neighbor Plan.

In each of the successive rulemakings to address good neighbor obligations with respect to an ozone NAAQS, the EPA has coordinated compliance requirements by allowing the participation of a state's EGUs in the most recent seasonal NO_X trading program to also satisfy any requirements to participate in a previous seasonal NO_X trading program established to address the state's good neighbor obligations with respect to a less protective NAAQS.[7] Because of the EPA's coordination efforts, for 19 of the states covered by the Good Neighbor Plan as signed, including Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas, participation of the state's EGUs in the Group 3 trading program not only serves as the mechanism for partially addressing the states' good neighbor obligations with respect to the 2015 ozone NAAQS, but also serves as the mechanism for addressing the states' good neighbor obligations with respect to the 2008 ozone NAAQS.[8] For eight of the states, including Arkansas, Kentucky, Louisiana, Mississippi, and Missouri, participation of the states' EGUs in the Group 3 trading program serves as the mechanism for addressing the states' good neighbor obligations with respect to the 1997 ozone NAAQS as well.[9]

Petitioners challenging the SIP Disapproval action have filed motions in several courts for partial stays of that action with respect to the SIPs submitted by particular states. Subsequent to the Good Neighbor Plan's signature date, courts have granted some of these motions. On May 1 and June 8, 2023, the U.S. Court of Appeals for the Fifth Circuit issued orders staying the SIP Disapproval action with respect to Louisiana, Mississippi, and Texas pending judicial review on the merits.[10] On May 25 and 26, 2023, the U.S. Court of Appeals for the Eighth Circuit issued orders staying the SIP Disapproval action with respect to Arkansas and Missouri pending judicial review on the merits.[11] On May 31, 2023, the U.S. Court of Appeals for the Sixth Circuit issued an order administratively staying the SIP Disapproval action with respect

[1] Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336 (February 13, 2023).

[2] Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards, 88 FR 36654 (June 5, 2023).

[3] *See generally id.* The Good Neighbor Plan's requirements for EGUs apply in 22 of the 23 covered states, while the requirements for non-EGU industrial sources apply in 20 of the 23 covered states.

[4] Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 FR 48208 (August 8, 2011). CSAPR addressed states' good neighbor obligations with respect to the 1997 ozone NAAQS, as well as the 1997 and 2006 NAAQS for fine particulate matter.

[5] Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 FR 74504 (October 26, 2016). The CSAPR Update addressed states' good neighbor obligations with respect to the 2008 ozone NAAQS.

[6] Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 86 FR 23054 (April 30, 2021). The Revised CSAPR Update readdressed states' good neighbor obligations with respect to the 2008 ozone NAAQS in response to the remand of the CSAPR Update in *Wisconsin* v. *EPA,* 938 F.3d 303 (D.C. Cir. 2019).

[7] *See, e.g.,* 81 FR 74509; 86 FR 23122.

[8] *See* 88 FR 36844.

[9] *See id.*

[10] Order, *Texas* v. *EPA,* No. 23–60069 (5th Cir. May 1, 2023); Order, *Texas* v. *EPA,* No. 23–60069 (5th Cir. June 8, 2023). The orders are available in the docket.

[11] Order, *Arkansas* v. *EPA,* No. 23–1320 (8th Cir. May 25, 2023); Order, *Missouri* v. *EPA,* No. 23–1719 (8th Cir. May 26, 2023); Order, *Union Electric Co.* v. *EPA,* No. 23–1751 (8th Cir. May 26, 2023). The orders are available in the docket.

to Kentucky pending review of Kentucky's stay motion.[12]

The EPA's authority under CAA section 110(c)(1) to establish the Good Neighbor Plan's FIP requirements for the sources in a given state is triggered by either the EPA's disapproval of the state's good neighbor SIP with respect to the 2015 ozone NAAQS or the EPA's finding of the state's failure to submit such a SIP. Accordingly, as a result of the orders partially staying the SIP Disapproval action, the EPA must act to ensure that the Good Neighbor Plan's requirements that were issued to address good neighbor obligations with respect to the 2015 ozone NAAQS and that apply to either EGUs or non-EGU industrial sources in each of the states for which a stay order has been issued will not take effect while the stay of the SIP Disapproval action as to that state remains in place. To ensure full compliance with the stay orders, the EPA is also staying these requirements for sources in Indian country located within the borders of a state covered by a stay order, including areas of Indian country not subject to the state's SIP authority.[13] However, as noted earlier in this section, the Group 3 trading program is also the mechanism to implement requirements previously established for EGUs in most of the covered states to address the states' good neighbor obligations with respect to the 2008 ozone NAAQS and, in some cases, the 1997 ozone NAAQS. The SIP Disapproval action was not a basis for the authority relied on by the EPA in the previous rulemakings to establish emissions reduction requirements with respect to the 2008 or 1997 ozone NAAQS, and the stay orders do not affect these pre-existing requirements. The EPA's authority for the rulemakings addressing the 2008 and 1997 ozone NAAQS remains in place. Implementing the stay orders therefore requires the EPA not only to stay the new requirements established for EGUs and non-EGU industrial sources in the Good Neighbor Plan to address their states' good neighbor obligations with respect to the 2015 ozone NAAQS, but also to preserve status quo requirements established in previous rulemakings to address their states' good neighbor obligations with respect to the 2008 and 1997 ozone NAAQS.

Thus, the EPA in this action is revising the Good Neighbor Plan FIP requirements and the regulations for the Group 2 trading program to require the EGUs in each state covered by a stay order for the SIP Disapproval action to participate in the Group 2 trading program instead of the Group 3 trading program while the stay for that state remains in place. A small number of conforming revisions are also being made to the regulations for the Group 1 and Group 3 trading programs. Together, the revisions preserve the status quo by making the trading program requirements that will apply to the EGUs in each state for which the SIP Disapproval action has been stayed substantively identical to the trading program requirements that would have applied to the EGUs in that state if the state had not been covered by the Good Neighbor Plan. The revisions to the trading program regulations are summarized in the remainder of this section and are discussed in detail in section II.A.2 of this document.[14]

First, for EGUs in Arkansas, Mississippi, Missouri, and Texas, which before the Good Neighbor Plan were covered by the Group 2 trading program as promulgated in the CSAPR Update rather than the Group 3 trading program, the revisions in this action restore the state emissions budgets, unit-level allowance allocation provisions, and banked allowance holdings that would have been in effect for the EGUs in these states under the Group 2 trading program in the absence of the Good Neighbor Plan.

Second, for EGUs in Kentucky and Louisiana, which before the Good Neighbor Plan were already covered by the Group 3 trading program as promulgated in the Revised CSAPR Update, the revisions in this action modify the Group 2 and Group 3 trading program regulations so as to establish under the Group 2 trading program the state emissions budgets, unit-level allowance allocation provisions, and banked allowance holdings that would have been in effect for the EGUs in these states under the Group 3 trading program in the absence of the Good Neighbor Plan.

Finally, for EGUs in all states that will now be covered by the Group 2 trading program, the revisions in this action establish two non-interchangeable subtypes of Group 2 allowances: CSAPR NO_X Ozone Season Original Group 2 allowances and CSAPR NO_X Ozone Season Expanded Group 2 allowances.[15] EGUs in Arkansas, Mississippi, Missouri, and Texas, which would have been covered by the Group 2 trading program in the absence of the Good Neighbor Plan, will use Original Group 2 allowances for compliance (as will EGUs in Iowa, Kansas, and Tennessee, which are not covered by the Good Neighbor Plan and remain in the Group 2 trading program). EGUs in Kentucky and Louisiana, which would have been covered by the Group 3 trading program in the absence of the Good Neighbor Plan, will use Expanded Group 2 allowances for compliance. The requirements to use different subtypes of Group 2 allowances will preserve the status quo distinction between these two sets of EGUs that already existed before the Good Neighbor Plan and that continues to exist with the stay of the Good Neighbor Plan as to these states, because the allowances that EGUs in Kentucky and Louisiana have used for compliance under the Group 3 trading program as promulgated in the Revised CSAPR Update are not interchangeable with the allowances that EGUs in the other states have used for compliance under the Group 2 trading program.

The amendments to the regulatory requirements for EGUs and non-EGU industrial sources that the EPA is finalizing in this action in response to the stay orders are being made on an interim basis and will remain in place while the judicial proceedings in which the stay orders were issued remain pending. After the courts have reached final determinations on the merits in those proceedings, the EPA will take further action consistent with the final determinations. At the time of this rulemaking, the EPA cannot predict how the Agency's future action may affect the amendments being finalized in this action.

2. Specific Regulatory Revisions

The regulatory revisions to 40 CFR part 52 that are being adopted in this action to implement the orders staying the SIP Disapproval action for non-EGU industrial sources in Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas and Indian country

[12] Order, *Kentucky* v. *EPA*, No. 23–3216 (6th Cir. May 31, 2023), available in the docket.

[13] For sources in areas of Indian country not subject to the SIP authority of the states within whose borders the areas of Indian country are located, the EPA issued the Good Neighbor Plan's requirements not under authority of CAA section 110(c)(1) but under authority of CAA section 301(d)(4). *See* 88 FR 36690–92. However, because the EPA exercised its authority under CAA section 301(d)(4) only with respect to areas of Indian country within the borders of states for which requirements were being issued under CAA section 110(c)(1), *id.* at 36692, these areas of Indian country are indirectly implicated by the orders partially staying the SIP Disapproval action for the respective states.

[14] The EPA has included documents in the docket that show all the regulatory revisions being adopted in this action in redline-strikeout format.

[15] The non-interchangeability will be automatically enforced through the use of different codes for the two subtypes of Group 2 allowances in the EPA's Allowance Management System, where all allowance allocations, transfers, and deductions under the Group 2 trading program are recorded.

within the borders of those states include the addition of text at § 52.40(c)(4) to stay the effectiveness of the Good Neighbor Plan's requirements for non-EGU industrial sources at §§ 52.41 through 52.46 and the remainder of § 52.40 for states covered by stay orders and the addition of parallel text in the state-specific subparts of part 52 for each of the states.[16]

The regulatory revisions to 40 CFR parts 52 and 97 that are being adopted in this action to implement the orders staying the SIP Disapproval action for EGUs in Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas and Indian country within the borders of those states while ensuring continued implementation of requirements established to address good neighbor obligations under rules promulgated before the Good Neighbor Plan include the following:

- The addition of text at § 52.38(b)(2)(iii)(D) to stay the effectiveness of the Good Neighbor Plan's requirements at § 52.38(b)(2)(iii)(A) and (B) for EGUs to participate in the enhanced Group 3 trading program for control periods after 2022 for states covered by stay orders, the addition of text at § 52.38(b)(2)(ii)(D) to require those EGUs to participate in the Group 2 trading program while that stay remains in place, and the addition of parallel text in the state-specific subparts of part 52 for each of the states.[17]
- The revision of text at § 52.38(b)(16)(ii)(B) to provide for continued administration by the EPA after 2022, for states covered by stay orders, of state Group 2 trading programs integrated with the federal Group 2 trading program under approved SIP revisions.[18]
- The revision and addition of text at § 97.802 to define ''Original'' and ''Expanded'' subtypes of CSAPR NO_X Ozone Season Group 2 allowances, with conforming revisions and additions at §§ 97.502, 97.1002, 97.811(d) and (e), 97.821(e), 97.526(d) and (e), 97.826(d) through (f), and 52.38(b)(14).
- The revision of text at §§ 97.806(c), 97.824(a) and (d), and 97.825(a) to provide for EGUs in states covered by stay orders and covered by the Group 3 trading program before 2023 to use Expanded Group 2 allowances for compliance and for EGUs in other states covered by the Group 2 trading program to use Original Group 2 allowances for compliance, with conforming revisions at § 52.38(b)(14).
- The revision of text at § 97.810(a) and (b) to provide EGUs in states covered by stay orders the same amounts for state emissions budgets, new unit set-asides, Indian country new unit set-asides, and variability limits that would have applied under the Group 2 trading program or the Group 3 trading program, as applicable for the state, in the absence of the Good Neighbor Plan.
- The revision of text at § 97.811(a)(2) and § 97.821(e) to provide EGUs in states covered by stay orders the same unit-level allocation and recordation provisions that would have applied under the Group 2 trading program or the Group 3 trading program, as applicable for the state, in the absence of the Good Neighbor Plan.[19]
- The revision of text at §§ 97.830(b)(1) and 97.834(d)(2)(i) to provide EGUs in states that were covered by the Group 3 trading program before 2023 the same deadlines for commencement of monitoring and reporting activities that would have applied in the absence of the Good Neighbor Plan.
- The addition of text at § 97.1026(e) to provide for the conversion of banked 2021–2022 Group 3 allowances held by EGUs in states that that were covered by the Group 3 trading program before 2023 into Expanded Group 2 allowances, with conforming revisions at §§ 97.502, 97.802, 97.1002, 97.824(c), and 52.38(b)(14).
- The revision of text at §§ 97.811(e)(1) and 97.826(e)(1) to exclude EGUs in states covered by stay orders from the Good Neighbor Plan's provisions converting banked 2017–2022 Original Group 2 allowances into Group 3 allowances and recalling previously allocated 2023–2024 Original Group 2 allowances.
- The revision of text at §§ 97.816(c), 97.818(f), and 97.820(c)(1)(iv), (c)(2)(iv), and (c)(5)(vi) to include the transition of states from the Group 3 trading program to the Group 2 trading program in the provisions that allow the EPA to treat certain certifications, applications, and notices of delegation as valid despite the use of terminology intended for use under a different trading program.
- The revision of text at §§ 97.526(e) and 97.826(f) and the addition of text at § 97.1026(f) to include the transition of states from the Group 3 trading program to the Group 2 trading program in the provisions that specify when and how an EGU in a state that has moved between trading programs may use allowances from a later trading program to meet surrender requirements for past control periods under a previous trading program, with conforming revisions at § 52.38(b)(14).
- The revision of text at § 97.526(d)(2)(ii) and 97.826(d)(3) to include the conversion of Group 3 allowances to Expanded Group 2 allowances in the provisions that address future conversions of allowances that were allocated for past control periods under a given trading program to an EGU in a state no longer covered by that trading program, where the allowances would have been included in a previous conversion to a different type of allowances if the allocations had been recorded before the previous conversion took place.

B. Deadline Corrections

In addition to the regulatory revisions described in section II.A of this document that are being made on an interim basis in response to judicial stay orders, in this action the EPA is also permanently revising three near-term deadlines that are incorrect in the Good Neighbor Plan as published in the **Federal Register**. Unlike the revisions described in section II.A of this document, these revisions apply to emissions sources in the states whose coverage under the Good Neighbor Plan is not affected by a stay order.

The first deadline correction concerns a quarterly reporting deadline applicable to EGUs in states that were already covered by the Group 2 trading program or the Group 3 trading program before the 2023 ozone season. As explained in the Good Neighbor Plan preamble, these EGUs will participate in the revised Group 3 trading program for the entire 2023 ozone season, subject to transitional provisions ensuring that the only substantive new regulatory

[16] *See* §§ 52.184(b)(2) (Arkansas), 52.940(c)(2) (Kentucky), 52.984(e)(2) (Louisiana), 52.1284(b)(2) (Mississippi), 52.1326(c)(2) (Missouri), and 52.2283(e)(2) (Texas).

[17] *See* §§ 52.184(a)(6) (Arkansas), 52.940(b)(6) (Kentucky), 52.984(d)(6) (Louisiana), 52.1284(a)(6) (Mississippi), 52.1326(b)(6) (Missouri), and 52.2283(d)(6) (Texas).

[18] This revision ensures that Missouri's good neighbor obligations with respect to the 2008 and 1997 NAAQS can continue to be met through the participation of the state's EGUs in the state Group 2 trading program adopted by the state and included in the SIP revision that was approved by the EPA at 84 FR 66316 (December 4, 2019).

[19] For sources in states that were not covered by the Group 3 trading program before the Good Neighbor Plan, the applicable notice of data availability (NODA) referenced in revised § 97.811(a)(2)(i) as identifying the unit-level allocations of Original Group 2 allowances to existing units will be the NODA published at 81 FR 67190 (September 30, 2016) to implement the CSAPR Update. For sources in states that were covered by the Group 3 trading program before the Good Neighbor Plan, the applicable NODA referenced in revised § 97.811(a)(2)(ii) as identifying the unit-level allocations of Expanded Group 2 allowances to existing units will be the NODA published at 86 FR 26719 (May 17, 2021) to implement the Revised CSAPR Update.

requirements in 2023—specifically, the emissions control stringencies reflected in the revised Group 3 trading program's state emissions budgets and assurance levels—will take effect only after the Rule's effective date.[20] The Group 3 trading program's deadline for EGUs to submit quarterly reports of emissions and operating data for the first two months of the May–September ozone season in 2023 would normally have been July 31, 2023 (the first business day at least 30 days after the end of the second calendar quarter), but the timing of publication in the **Federal Register** caused the Good Neighbor Plan's effective date to fall four days after this date, on August 4, 2023. Accordingly, the EPA is extending the deadline in 40 CFR 97.1034(d)(3) by which EGUs subject to the Group 3 trading program must submit quarterly reports for this calendar quarter to August 4, 2023.[21] Further, because the quarterly reports required under the Group 3 trading program are consolidated with the quarterly reports required under several other EPA programs, the EPA is also amending 40 CFR 97.1034(d)(4) to similarly extend these EGUs' reporting deadlines under the other programs.

The second deadline correction concerns a quarterly reporting deadline applicable to EGUs in states that were not already covered by the Group 2 trading program or the Group 3 trading program before the 2023 ozone season. EGUs in these states will begin to participate in the Group 3 trading program as of the Good Neighbor Plan's effective date, and the regulations as published in the Rule correctly provide that most of these EGUs will be subject to the program's monitoring and reporting requirements for emissions occurring on and after August 4, 2023.[22] However, a separate regulatory provision incorrectly identifies the ending date of the first calendar quarter for which these EGUs must submit quarterly reports under the Group 3 trading program as June 30, 2023. The EPA is amending 40 CFR 97.1034(d)(2)(i)(C) to indicate the correct quarterly ending date of September 30, 2023. The deadline for EGUs to submit quarterly reports for this calendar quarter will be October 30, 2023.

The third deadline correction concerns a deadline for submission of initial notifications applicable to furnaces in the Glass and Glass Product Manufacturing industry that are subject to requirements under the Good Neighbor Plan. Because of a typographical error in the document submitted for publication in the **Federal Register**,the Rule as published incorrectly specifies a submission deadline of June 23, 2023 (the first business day at least 18 days after the Rule's publication date). The EPA is amending 40 CFR 52.44(j)(2) to specify the intended submission deadline of December 4, 2023 (the first business day at least *180* days after the Rule's publication date).

III. Rulemaking Procedures and Findings of Good Cause

As noted in section I.C of this document, the EPA's authority for the rulemaking procedures followed in this action is provided by APA section 553.[23] In general, an agency issuing a rule under the procedures in APA section 553 must provide prior notice and an opportunity for public comment, but APA section 553(b)(B) includes an exemption from notice-and-comment requirements ''when the agency for good cause finds (and incorporates the finding and a brief statement of reasons therefor in the rule issued) that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest.'' This action is being issued as an interim final rule without prior notice or opportunity for public comment because the EPA finds that the APA ''good cause'' exemption from notice-and-comment requirements applies here.

The EPA finds good cause to forgo notice-and-comment procedures because such procedures are both impracticable and unnecessary for this action. First, following notice-and-comment procedures is impracticable for the portions of this action responding to the stay orders because such procedures would require more time than is available. The earliest stay order to which the EPA must respond in this action was issued on May 1, 2023, just over three months before the Good Neighbor Plan's upcoming effective date on August 4, 2023, which is the date by which this action responding to the stay order must be effective. The most recent of the subsequent stay orders to which the EPA's action must also respond was issued less than two months before the Rule's upcoming effective date. The EPA does not consider even the maximum three-month period sufficient time in which to conduct a notice-and-comment rulemaking encompassing the time to, at a minimum, evaluate possible actions for responding to the stay orders, prepare and publish a proposal describing the action identified through that evaluation, wait for comments on the proposal, review the comments received, and prepare and publish a final rule and response to comments. It is not possible for all of these steps to be completed within a three-month period for this action.

Second, following notice-and-comment procedures is unnecessary for this action. With respect to the portions of this action that respond to the stay orders, the EPA has no discretion as to the regulatory revisions that stay the effectiveness of the Good Neighbor Plan's requirements for sources in the states covered by stay orders. While some superficial discretion exists concerning the specific design of the regulatory revisions that provide an alternate mechanism for EGUs in states covered by the stay orders to continue to address the states' good neighbor obligations with respect to the 2008 and 1997 NAAQS, no discretion exists as to the function of that design, which is to maintain the status quo by implementing requirements that are substantively identical to the pre-existing requirements that would have continued to apply in the absence of the Good Neighbor Plan. The EPA's design for the regulatory revisions in this action accomplishes this function. Taking comment on the portions of the action that respond to the stay orders so as to allow the public to advocate for not staying the Good Neighbor Plan's requirements, not adopting regulatory

[20] *See* 88 FR 36775–76; 88 FR 36811–13.

[21] All the EGUs that are required under the Good Neighbor Plan to submit quarterly reports for the second calendar quarter of 2023 already participate in either the Group 2 trading program or the Group 3 trading program and therefore have already installed and certified the necessary monitoring systems. The data elements of the quarterly reports that these EGUs are required to submit under the Group 3 trading program for their ozone season emissions in 2023 are identical to the data elements of the quarterly reports that the EGUs were required to submit under the Group 2 trading program or Group 3 trading program for their ozone season emissions in 2022 and previous years.

[22] *See* 40 CFR 97.1030(b)(1)(iii). Most EGUs covered under the Good Neighbor Plan that do not already participate in the Group 2 trading program or the Group 3 trading program are already subject to closely related monitoring and reporting requirements under other EPA programs and consequently have already installed and certified the monitoring systems necessary to monitor and report under the Group 3 trading program. For the small number of EGUs in these states that have not already been required to install and certify the necessary monitoring systems under another EPA program, the deadline to begin monitoring and reporting under the Group 3 trading program will be either January 31, 2024 (180 days after the Rule's effective date), for units that report on a year-round basis, or May 1, 2024, for units that report on an ozone season-only basis. *See* 40 CFR 97.1030(b)(1)(iv) and (b)(3).

[23] Under CAA section 307(d)(1)(B), the EPA's revision of a FIP under CAA section 110(c) would normally be subject to the rulemaking procedural requirements of CAA section 307(d), including notice-and-comment procedures, but CAA section 307(d) does not apply ''in the case of any rule or circumstance referred to in subparagraphs (A) or (B) of [APA section 553(b)].'' CAA section 307(d)(1).

revisions needed to implement requirements that are substantively identical to the requirements that would have applied in the absence of the Good Neighbor Plan, or adopting superficially different regulatory revisions to accomplish the same function would serve no purpose and is therefore unnecessary.[24]

With respect to the portions of this action that correct deadlines, each of the deadlines that is incorrect as published in the Good Neighbor Plan precedes the Rule's actual effective date and therefore could not be implemented as published. In the cases of the two deadlines that were incorrect as published because of the timing of the Rule's publication, the amended deadlines of August 4, 2023, and September 30, 2023, are the earliest possible revised deadlines that are both feasible in light of the Good Neighbor Plan's actual effective date and also consistent with the normal timing and sequence of monitoring and reporting activities under the Group 3 trading program regulations. In the case of the deadline that was incorrect as published because of a typographical error, the amended deadline of December 4, 2023, is the same deadline that has already been published in parallel provisions of the Good Neighbor Plan's regulations for other non-EGU industrial sources.[25] Because both the need for the corrections and the specific corrections that should be made are clear, taking comment to allow the public to advocate for not correcting the deadlines or for making different corrections would serve no purpose and is therefore unnecessary.

The regulatory revisions made in this action will take effect on August 4, 2023, the effective date of the Good Neighbor Plan. In general, an agency issuing a rule under APA section 553 must provide for a period of at least 30 days between the rule's dates of publication and effectiveness, but APA section 553(d) includes several exceptions. Under APA section 553(d)(1), an exception applies to a rule that ''grants or recognizes an exemption or relieves a restriction.'' Because the portions of this action that stay the effectiveness of the Good Neighbor Plan's requirements for the sources in certain states grant an exemption (on an interim basis while the stay remains in place), the normal 30-day minimum period between this action's dates of publication and effectiveness is not required. The EPA is making these portions of the action effective as of the Good Neighbor Plan's effective date to comply with the stay orders.

Under APA section 553(d)(3), the normal 30-day minimum period between a rule's dates of publication and effectiveness does not apply ''as otherwise provided by the agency for good cause found and published with the rule.'' With respect to the portions of this action that provide an alternate mechanism for EGUs in states covered by the stay orders to continue to address the states' good neighbor obligations under rules issued before the Good Neighbor Plan and the portions of this action that correct certain deadlines, the EPA finds good cause to make the regulatory revisions effective on August 4, 2023, the effective date of the Good Neighbor Plan, even though that date is less than 30 days after the publication date of this action, for the following reasons. First, the regulatory revisions that facilitate continued implementation of requirements addressing good neighbor obligations under previous rules benefit the public by avoiding the possibility that interruption of the requirements would cause air quality degradation. Second, both these regulatory revisions and the regulatory revisions that correct deadlines benefit the regulated community by clarifying the regulatory requirements that apply in light of the stay orders and the timing of publication of the Good Neighbor Plan. Finally, making the regulatory revisions effective less than 30 days after this action's publication date does not violate the purpose of the normal requirement for a 30-day minimum period, which is ''to give affected parties a reasonable time to adjust their behavior before the final rule takes effect.''[26] The regulatory revisions in this action facilitating continued implementation of previously applicable requirements impose no requirements on any source that differ substantively from the requirements that would have applied to that source in the absence of the Good Neighbor Plan, and the deadline corrections in this action extend the deadlines in the Rule as published. Thus, no affected party needs time to adjust its behavior in preparation for these regulatory revisions.

IV. Request for Comment

As explained in section III of this document, the EPA finds good cause to take this interim final action without prior notice or opportunity for public comment. However, the EPA is providing an opportunity for comment on the content of the amendments. The EPA requests comment on this rule. The EPA is not reopening for comment any provisions of the Good Neighbor Plan, 40 CFR part 52, or 40 CFR part 97 other than the specific provisions that are expressly added or amended in this rule.

V. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review, as Amended by Executive Order 14094: Modernizing Regulatory Review

This action is not a significant regulatory action as defined in Executive Order 12866, as amended by Executive Order 14094, and was therefore not subject to a requirement for Executive Order 12866 review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the Paperwork Reduction Act (PRA), 44 U.S.C. 3501 *et seq.* The Office of Management and Budget (OMB) has previously approved the information collection activities that will apply to the EGUs affected by this action and has assigned OMB control numbers 2060–0258 and 2060–0667. Additional information collection activities that will apply to EGUs and non-EGU industrial sources under the Good Neighbor Plan have been submitted to OMB for approval in conjunction with that rulemaking. This action makes no changes to the information collection activities under the previously approved information collection requests (ICRs) or the additional information collection activities for which approval has been requested in the Good Neighbor Plan's ICRs.

C. Regulatory Flexibility Act (RFA)

This action is not subject to the Regulatory Flexibility Act (RFA), 5.U.S.C. 601–612. The RFA applies only to rules subject to notice-and-comment rulemaking requirements under the Administrative Procedure Act (APA), 5 U.S.C. 553, or any other statute. This rule is not subject to notice-and-comment requirements because the

[24] To illustrate, the EPA could in theory preserve the status quo for EGUs in Kentucky and Louisiana by promulgating an entire set of trading program regulations under 40 CFR part 97 replicating the entire set of Group 3 trading program regulations as promulgated in the Revised CSAPR Update without the subsequent revisions promulgated in the Good Neighbor Plan to address states' good neighbor obligations with respect to the 2015 ozone NAAQS. However, the outcome would be substantively identical to the approach the EPA is taking here.

[25] *See* 40 CFR 52.42(g)(2); 40 CFR 52.43(h)(2).

[26] *Omnipoint Corp.* v. *FCC,* 78 F.3d 620, 630 (D.C. Cir. 1996).

Agency has invoked the APA "good cause" exemption under 5 U.S.C. 553(b).

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in the Unfunded Mandates Reform Act (UMRA), 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments or the private sector. This action simply stays the effectiveness of certain regulatory requirements for certain sources on an interim basis in response to procedural court orders while ensuring that previously applicable regulatory requirements remain in effect.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. This action simply stays the effectiveness of certain regulatory requirements for certain sources on an interim basis in response to procedural court orders while ensuring that previously applicable regulatory requirements remain in effect. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of "covered regulatory action" in section 2–202 of the Executive Order. This action responds to court orders issued by the U.S. Courts of Appeals for the Fifth, Sixth, and Eighth Circuits and the EPA lacks discretion to deviate from those orders. The EPA's assessment of health and safety risks for the action establishing the requirements that are being stayed is discussed in Chapter 5 of the regulatory impact analysis for the Good Neighbor Plan.[27]

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This rulemaking does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations (people of color and/or Indigenous peoples) and low-income populations.

This action responds to court orders issued by the U.S. Courts of Appeals for the Fifth, Sixth, and Eighth Circuits and the EPA lacks discretion to deviate from those orders. The EPA's assessment of environmental justice considerations for the action establishing the requirements that are being stayed is discussed in section VII of the Good Neighbor Plan preamble.[28]

K. Congressional Review Act (CRA)

This action is subject to the Congressional Review Act (CRA), 5 U.S.C. 801–808, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United States. The CRA allows the issuing agency to make a rule effective sooner than otherwise provided by the CRA if the agency makes a good cause finding that notice and comment rulemaking procedures are impracticable, unnecessary, or contrary to the public interest (5 U.S.C. 808(2)). The EPA has made a good cause finding for this rule as discussed in section III of this document, including the basis for that finding.

L. Judicial Review

CAA section 307(b)(1) governs judicial review of final actions by the EPA. This section provides, in part, that petitions for review must be filed in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit): (i) when the agency action consists of "nationally applicable regulations promulgated, or final actions taken, by the Administrator," or (ii) when such action is locally or regionally applicable, but "such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination." For locally or regionally applicable final actions, the CAA reserves to the EPA complete discretion to decide whether to invoke the exception in (ii).[29]

This rulemaking is "nationally applicable" within the meaning of CAA section 307(b)(1). In this action, in response to court orders, the EPA is amending on an interim basis the Good Neighbor Plan,[30] which the EPA developed by applying a uniform legal interpretation and common, nationwide analytical methods to address the requirements of CAA section 110(a)(2)(D)(i)(I) concerning interstate transport of pollution (*i.e.,* "good neighbor" requirements) for the 2015 ozone NAAQS. Based on that nationwide analysis, the Good Neighbor Plan established FIP requirements for sources in 23 states located across eight EPA Regions and ten federal judicial circuits. Given that this action amends an action implementing the good neighbor requirements of CAA section 110(a)(2)(D)(i)(I) in a large number of states located across the country and given the interdependent nature of interstate pollution transport and the common core of knowledge and analysis involved in promulgating the FIP requirements, this is a "nationally applicable" action within the meaning of CAA section 307(b)(1).

In the alternative, to the extent a court finds this action to be locally or regionally applicable, the Administrator is exercising the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of

[27] *See* Regulatory Impact Analysis for the Final Federal Good Neighbor Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard (March 2023) at 197–257, available in the docket.

[28] *See* 88 FR 36844–46.

[29] *Sierra Club* v. *EPA,* 47 F.4th 738, 745 (D.C. Cir. 2022) ("EPA's decision whether to make and publish a finding of nationwide scope or effect is committed to the agency's discretion and thus is unreviewable"); *Texas* v. *EPA,* 983 F.3d 826, 834–35 (5th Cir. 2020).

[30] The Good Neighbor Plan is nationally applicable or based on a determination of nationwide scope or effect found and published by the EPA. *See* 88 FR 36859–60.

''nationwide scope or effect'' within the meaning of CAA section 307(b)(1). In this action, in response to court orders, the EPA is amending on an interim basis the Good Neighbor Plan, an action in which the EPA interpreted and applied section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS based on a common core of nationwide policy judgments and technical analysis concerning the interstate transport of pollutants throughout the continental United States. Based on that nationwide analysis, the Good Neighbor Plan established FIP requirements for sources in 23 states located across eight EPA Regions and ten federal judicial circuits. This action adjusts temporarily the scope and operation of the Good Neighbor Plan for six states in response to court orders, and also implements necessary measures to ensure the status quo is maintained with respect to existing obligations under previously issued regulations (that were themselves nationally applicable or based on a determination of nationwide scope or effect found and published by the EPA [31]). This action also adjusts certain deadlines for all states that remain covered by the Good Neighbor Plan.

The Administrator finds that, like the Good Neighbor Plan which it amends, this action is a matter on which national uniformity in judicial resolution of any petitions for review is desirable, to take advantage of the D.C. Circuit's administrative law expertise, and to facilitate the orderly development of the basic law under the Act. The Administrator also finds that consolidated review of this action in the D.C. Circuit will avoid piecemeal litigation in the regional circuits, further judicial economy, and eliminate the risk of inconsistent results for different states, and that a nationally consistent approach to the CAA's mandate concerning interstate transport of ozone pollution constitutes the best use of Agency resources.

For these reasons, this final action is nationally applicable or, alternatively, the Administrator is exercising the complete discretion afforded to him by the CAA and finds that this final action is based on a determination of nationwide scope or effect for purposes of CAA section 307(b)(1) and is publishing that finding in the **Federal Register**. Under CAA section 307(b)(1), petitions for judicial review of this action must be filed in the D.C. Circuit by September 29, 2023.

[31] *See* 86 FR 23163–64; 81 FR 74585–86.

List of Subjects

40 CFR Part 52

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Sulfur dioxide.

40 CFR Part 97

Environmental protection, Administrative practice and procedure, Air pollution control, Electric power plants, Nitrogen oxides, Ozone, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide.

Michael S. Regan,
Administrator.

For the reasons stated in the preamble, parts 52 and 97 of title 40 of the Code of Federal Regulations are amended as follows:

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—General Provisions

■ 2. Amend § 52.38 by:
■ a. Adding paragraphs (b)(2)(ii)(D) and (b)(2)(iii)(D);
■ b. In paragraph (b)(11)(iii)(D), removing ''and'' after the semicolon;
■ c. In paragraph (b)(14)(i)(F), removing ''and'' after the semicolon;
■ d. Revising paragraph (b)(14)(i)(G);
■ e. Adding paragraph (b)(14)(i)(H);
■ f. Revising paragraphs (b)(14)(iii) introductory text and (b)(14)(iii)(B);
■ g. In paragraph (b)(14)(iii)(C), adding ''Original'' before ''Group 2 allowances'' each time it appears; and
■ h. In paragraph (b)(16)(ii)(B), adding ''and not listed in paragraph (b)(2)(ii)(D)(*2*) of this section'' before ''and any control period''.

The additions and revisions read as follows:

§ 52.38 What are the requirements of the Federal Implementation Plans (FIPs) for the Cross-State Air Pollution Rule (CSAPR) relating to emissions of nitrogen oxides?

* * * * *

(b) * * *
(2) * * *
(ii) * * *
(D) Notwithstanding any other provision of this part:

(*1*) While a stay under paragraph (b)(2)(iii)(D)(*1*) of this section is in effect for the sources in a State and Indian country located within the borders of such State with regard to emissions occurring in a control period in a given year—

(*i*) The provisions of subpart EEEEE of part 97 of this chapter (as modified in any approval of a SIP revision for such State by the Administrator under paragraph (b)(8) of this section) or the provisions of a SIP revision approved for such State by the Administrator under paragraph (b)(9) of this section, if any, shall apply to the sources in such State and areas of Indian country within the borders of such State subject to the State's SIP authority, and the provisions of subpart EEEEE of part 97 of this chapter shall apply to the sources in areas of Indian country within the borders of such State not subject to the State's SIP authority, with regard to emissions occurring in such control period; and

(*ii*) Such State shall be deemed to be listed in this paragraph (b)(2)(ii)(D)(*1*) for purposes of this part and part 97 of this chapter.

(*2*) While a stay under paragraph (b)(2)(iii)(D)(*2*) of this section is in effect for the sources in a State and Indian country located within the borders of such State with regard to emissions occurring in a control period in a given year—

(*i*) The provisions of subpart EEEEE of part 97 of this chapter (as modified in any approval of a SIP revision for such State by the Administrator under paragraph (b)(8) of this section) or the provisions of a SIP revision approved for such State by the Administrator under paragraph (b)(9) of this section, if any, shall apply to the sources in such State and areas of Indian country within the borders of such State subject to the State's SIP authority, and the provisions of subpart EEEEE of part 97 of this chapter shall apply to the sources in areas of Indian country within the borders of such State not subject to the State's SIP authority, with regard to emissions occurring in such control period; and

(*ii*) Such State shall be deemed to be listed in this paragraph (b)(2)(ii)(D)(*2*) for purposes of this part and part 97 of this chapter.

(iii) * * *
(D) Notwithstanding any other provision of this part:

(*1*) The effectiveness of paragraph (b)(2)(iii)(A) of this section is stayed for sources in Kentucky and Louisiana and Indian country located within the borders of such States with regard to emissions occurring in 2023 and thereafter. While a stay under this paragraph (b)(2)(iii)(D)(*1*) is in effect for a State, such State shall be deemed not to be listed in paragraph (b)(2)(iii)(A) of this section for purposes of part 97 of this chapter for a control period after 2022.

(*2*) The effectiveness of paragraph (b)(2)(iii)(B) of this section is stayed for sources in Arkansas, Mississippi, Missouri, and Texas and Indian country located within the borders of such States with regard to emissions occurring in 2023 and thereafter. While a stay under this paragraph (b)(2)(iii)(D)(*2*) is in effect for a State, such State shall be deemed not to be listed in paragraph (b)(2)(iii)(B) of this section for purposes of part 97 of this chapter.

* * * * *

(14) * * *

(i) * * *

(G) The provisions in § 97.526(e) of this chapter or § 97.826(f) of this chapter (concerning the use of CSAPR NO_X Ozone Season Original Group 2 allowances, CSAPR NO_X Ozone Season Expanded Group 2 allowances, or CSAPR NO_X Ozone Season Group 3 allowances to satisfy requirements to hold CSAPR NO_X Ozone Season Group 1 allowances or the use of CSAPR NO_X Ozone Season Expanded Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances to satisfy requirements to hold CSAPR NO_X Ozone Season Original Group 2 allowances); and

(H) The provisions in §§ 97.806(c), 97.824(a) and (d), and 97.825(a) of this chapter (concerning the situations for which compliance requirements are defined in terms of either CSAPR NO_X Ozone Season Original Group 2 allowances or CSAPR NO_X Ozone Season Expanded Group 2 allowances).

* * * * *

(iii) Notwithstanding any discontinuation pursuant to paragraphs (b)(2)(i)(B), (b)(2)(ii)(B) or (C), (b)(2)(iii)(D)(*1*), or (b)(13)(i) of this section of the applicability of subpart BBBBB, EEEEE, or GGGGG of part 97 of this chapter to the sources in a State and areas of Indian country within the borders of the State subject to the State's SIP authority with regard to emissions occurring in any control period, the following provisions shall continue to apply with regard to all CSAPR NO_X Ozone Season Group 1 allowances, CSAPR NO_X Ozone Season Group 2 allowances, and CSAPR NO_X Ozone Season Group 3 allowances at any time allocated for any control period to any source or other entity in the State and areas of Indian country within the borders of the State subject to the State's SIP authority and shall apply to all entities, wherever located, that at any time held or hold such allowances:

* * * * *

(B) The provisions of §§ 97.526(d), 97.826(d) and (e), and 97.1026(e) of this chapter (concerning the conversion of unused CSAPR NO_X Ozone Season Group 1 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Original Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances, the conversion of unused CSAPR NO_X Ozone Season Original Group 2 allowances allocated for specified control periods to different amounts of CSAPR NO_X Ozone Season Group 3 allowances, and the conversion of unused CSAPR NO_X Ozone Season Group 3 allowances allocated for specified control periods to CSAPR NO_X Ozone Season Expanded Group 2 allowances); and

* * * * *

■ 3. Amend § 52.40 by adding paragraph (c)(4) to read as follows:

§ 52.40 What are the requirements of the Federal Implementation Plans (FIPs) relating to ozone season emissions of nitrogen oxides from sources not subject to the CSAPR ozone season trading program?

* * * * *

(c) * * *

(4) Notwithstanding any other provision of this part, the effectiveness of paragraphs (a) and (b), (c)(1) through (3), and (d) through (g) of this section and §§ 52.41, 52.42, 52.43, 52.44, 52.45, and 52.46 is stayed for sources located in Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas, including Indian country located within the borders of such States.

* * * * *

§ 52.44 [Amended]

■ 4. Amend § 52.44(j)(2) by removing ''June 23, 2023'' and adding in its place ''December 4, 2023''.

Subpart E—Arkansas

■ 5. Amend § 52.184 by:

■ a. Adding paragraph (a)(6); and

■ b. Redesignating paragraph (b) as paragraph (b)(1) and adding paragraph (b)(2).

The additions read as follows:

§ 52.184 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(6) Notwithstanding any other provision of this part, the effectiveness of paragraph (a)(3) of this section is stayed with regard to emissions occurring in 2023 and thereafter, provided that while such stay remains in effect, the provisions of paragraph (a)(2) of this section shall apply with regard to such emissions.

(b) * * *

(2) Notwithstanding any other provision of this part, the effectiveness of paragraph (b)(1) of this section is stayed.

Subpart S—Kentucky

■ 6. Amend § 52.940 by:

■ a. Adding paragraph (b)(6); and

■ b. Redesignating paragraph (c) as paragraph (c)(1) and adding paragraph (c)(2).

The additions read as follows:

§ 52.940 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(6) Notwithstanding any other provision of this part, the effectiveness of paragraph (b)(3) of this section is stayed with regard to emissions occurring in 2023 and thereafter, provided that while such stay remains in effect, the provisions of paragraph (b)(2) of this section shall apply with regard to such emissions.

(c) * * *

(2) Notwithstanding any other provision of this part, the effectiveness of paragraph (c)(1) of this section is stayed.

Subpart T—Louisiana

■ 7. Amend § 52.984 by:

■ a. Adding paragraph (d)(6); and

■ b. Redesignating paragraph (e) as paragraph (e)(1) and adding paragraph (e)(2).

The additions read as follows:

§ 52.984 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(6) Notwithstanding any other provision of this part, the effectiveness of paragraph (d)(3) of this section is stayed with regard to emissions occurring in 2023 and thereafter, provided that while such stay remains in effect, the provisions of paragraph (d)(2) of this section shall apply with regard to such emissions.

(e) * * *

(2) Notwithstanding any other provision of this part, the effectiveness of paragraph (e)(1) of this section is stayed.

Subpart Z—Mississippi

■ 8. Amend § 52.1284 by:
■ a. Adding paragraph (a)(6); and
■ b. Redesignating paragraph (b) as paragraph (b)(1) and adding paragraph (b)(2).

The additions read as follows:

§ 52.1284 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

(a) * * *

(6) Notwithstanding any other provision of this part, the effectiveness of paragraph (a)(3) of this section is stayed with regard to emissions occurring in 2023 and thereafter, provided that while such stay remains in effect, the provisions of paragraph (a)(2) of this section shall apply with regard to such emissions.

(b) * * *

(2) Notwithstanding any other provision of this part, the effectiveness of paragraph (b)(1) of this section is stayed.

Subpart AA—Missouri

■ 9. Amend § 52.1326 by:
■ a. Adding paragraph (b)(6); and
■ b. Redesignating paragraph (c) as paragraph (c)(1) and adding paragraph (c)(2).

The additions read as follows:

§ 52.1326 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(b) * * *

(6) Notwithstanding any other provision of this part, the effectiveness of paragraph (b)(3) of this section is stayed with regard to emissions occurring in 2023 and thereafter, provided that while such stay remains in effect, the provisions of paragraph (b)(2) of this section shall apply with regard to such emissions.

(c) * * *

(2) Notwithstanding any other provision of this part, the effectiveness of paragraph (c)(1) of this section is stayed.

Subpart SS—Texas

■ 10. Amend § 52.2283 by:
■ a. Adding paragraph (d)(6); and
■ b. Redesignating paragraph (e) as paragraph (e)(1) and adding paragraph (e)(2).

The additions read as follows:

§ 52.2283 Interstate pollutant transport provisions; What are the FIP requirements for decreases in emissions of nitrogen oxides?

* * * * *

(d) * * *

(6) Notwithstanding any other provision of this part, the effectiveness of paragraph (d)(3) of this section is stayed with regard to emissions occurring in 2023 and thereafter, provided that while such stay remains in effect, the provisions of paragraph (d)(2) of this section shall apply with regard to such emissions.

(e) * * *

(2) Notwithstanding any other provision of this part, the effectiveness of paragraph (e)(1) of this section is stayed.

PART 97—FEDERAL NO_X BUDGET TRADING PROGRAM, CAIR NO_X AND SO_2 TRADING PROGRAMS, CSAPR NO_X AND SO_2 TRADING PROGRAMS, AND TEXAS SO_2 TRADING PROGRAM

■ 11. The authority citation for part 97 continues to read as follows:

Authority: 42 U.S.C. 7401, 7403, 7410, 7426, 7491, 7601, and 7651, *et seq.*

Subpart BBBBB—CSAPR NO_X Ozone Season Group 1 Trading Program

■ 12. Amend § 97.502 by:
■ a. Adding in alphabetical order a definition of "CSAPR NO_X Ozone Season Expanded Group 2 allowance";
■ b. Revising the definition of "CSAPR NO_X Ozone Season Group 2 allowance"; and
■ c. Adding in alphabetical order a definition of "CSAPR NO_X Ozone Season Original Group 2 allowance".

The revision and additions read as follows:

§ 97.502 Definitions.

* * * * *

CSAPR NO_X Ozone Season Expanded Group 2 allowance means a CSAPR NO_X Ozone Season Group 2 allowance allocated for a control period after 2022 under subpart EEEEE of this part, § 97.526(d), or § 97.1026(e) to a unit in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) or allocated or auctioned for a control period after 2022 in accordance with the provisions of a SIP revision approved for such a State by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter.

* * * * *

CSAPR NO_X Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart EEEEE of this part, § 97.526(d), or § 97.1026(e), or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 2 Trading Program, where each CSAPR NO_X Ozone Season Group 2 allowance is either a CSAPR NO_X Ozone Season Original Group 2 allowance or a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

CSAPR NO_X Ozone Season Original Group 2 allowance means a CSAPR NO_X Ozone Season Group 2 allowance other than a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

■ 13. Amend § 97.526 by:
■ a. In paragraphs (d)(1)(iii) and (iv) and (d)(2)(i), adding "Original" before "Group 2 allowances" each time it appears;
■ b. Redesignating paragraph (d)(2)(ii) as paragraph (d)(2)(ii)(A);
■ c. In newly redesignated paragraph (d)(2)(ii)(A), removing "After the Administrator" and adding in its place "Except as provided in paragraph (d)(2)(ii)(B) of this section, after the Administrator";
■ d. Adding paragraph (d)(2)(ii)(B);
■ e. Revising paragraph (e) introductory text;
■ f. In paragraph (e)(1), adding "Original" before "Group 2 allowances";
■ g. Redesignating paragraph (e)(2) as paragraph (e)(2)(i);
■ h. In newly redesignated paragraph (e)(2)(i), removing "After the Administrator" and adding in its place "Except as provided in paragraph (e)(2)(ii) of this section, after the Administrator"; and
■ i. Adding paragraph (e)(2)(ii).

The additions and revision read as follows:

§ 97.526 Banking and conversion.

* * * * *

(d) * * *
(2) * * *
(ii) * * *

(B) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and §§ 97.826(d)(1) and 97.1026(e), upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Group 1 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Group 1 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Expanded Group 2 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(d)(1)(i)(D).

* * * * *

(e) Notwithstanding any other provision of this subpart or any SIP revision approved under § 52.38(b)(4) or (5) of this chapter, CSAPR NO_X Ozone Season Original Group 2 allowances, CSAPR NO_X Ozone Season Expanded Group 2 allowances, or CSAPR NO_X Ozone Season Group 3 allowances may be used to satisfy requirements to hold CSAPR NO_X Ozone Season Group 1 allowances under this subpart as follows, provided that nothing in this paragraph (e) alters the time as of which any such allowance holding requirement must be met or limits any consequence of a failure to timely meet any such allowance holding requirement:

* * * * *

(2) * * *

(ii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and §§ 97.826(d)(1) and 97.1026(e), the owner or operator of a CSAPR NO_X Ozone Season Group 1 source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 1 allowances for the control period in 2015 or 2016 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Expanded Group 2 allowances for the control period in 2021 (or any later control period for which the allowance transfer deadline defined in § 97.802 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Group 1 allowances divided by the conversion factor determined under paragraph (d)(1)(ii) of this section and further divided by the conversion factor determined under § 97.826(d)(1)(i)(D).

* * * * *

Subpart EEEEE—CSAPR NO_X Ozone Season Group 2 Trading Program

■ 14. Amend § 97.802 by:

■ a. In the definition of ''Allocate or allocation'', removing ''§ 97.526(d), and'' and adding in its place ''§§ 97.526(d), 97.826(d), and 97.1026(e), and'';

■ b. In the definition of ''Common designated representative's assurance level'', paragraph (2), removing ''§ 97.526(d)'' and adding in its place ''§ 97.526(d), § 97.826(d), or § 97.1026(e)'';

■ c. Adding in alphabetical order a definition of ''CSAPR NO_X Ozone Season Expanded Group 2 allowance'';

■ d. Revising the definition of ''CSAPR NO_X Ozone Season Group 2 allowance''; and

■ e. Adding in alphabetical order a definition of ''CSAPR NO_X Ozone Season Original Group 2 allowance''.

The additions and revision read as follows:

§ 97.802 Definitions.

* * * * *

CSAPR NO_X Ozone Season Expanded Group 2 allowance means a CSAPR NO_X Ozone Season Group 2 allowance allocated for a control period after 2022 under this subpart, § 97.526(d), or § 97.1026(e) to a unit in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) or allocated or auctioned for a control period after 2022 in accordance with the provisions of a SIP revision approved for such a State by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter.

* * * * *

CSAPR NO_X Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under this subpart, § 97.526(d), or § 97.1026(e), or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 2 Trading Program, where each CSAPR NO_X Ozone Season Group 2 allowance is either a CSAPR NO_X Ozone Season Original Group 2 allowance or a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

CSAPR NO_X Ozone Season Original Group 2 allowance means a CSAPR NO_X Ozone Season Group 2 allowance other than a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

■ 15. Amend § 97.806 by:

■ a. In paragraph (c)(1)(i), adding ''for such source'' after ''available for deduction'';

■ b. In paragraph (c)(2)(i) introductory text, adding ''for such group'' after ''available for deduction'';

■ c. In paragraph (c)(4), amend the paragraph heading by adding ''*and type*'' after ''*Vintage*''; and

■ d. Adding paragraphs (c)(4)(iii) and (iv).

The additions read as follows:

§ 97.806 Standard requirements.

* * * * *

(c) * * *

(4) * * *

(iii) Except as provided in paragraph (c)(4)(iv) of this section, a CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(i), (c)(1)(ii)(A), and (c)(2)(i) through (iii) of this section must be a CSAPR NO_X Ozone Season Original Group 2 allowance.

(iv) A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(i), (c)(1)(ii)(A), and (c)(2)(i) through (iii) of this section for a source or group of sources in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (or Indian country within the borders of such a State) for a control period after 2022 must be a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

■ 16. Amend § 97.810 by:

■ a. In paragraphs (a)(2)(i) and (ii), removing ''through 2022'' and adding in its place ''and thereafter'';

■ b. Adding paragraphs (a)(8)(iv) through (vi) and (a)(9)(iv) through (vi);

■ c. In paragraphs (a)(12)(i) through (iii), (a)(13)(i) and (ii), (a)(20)(i) through (iii), and (b)(2), removing ''through 2022'' and adding in its place ''and thereafter'';

■ d. Redesignating paragraph (b)(8) as paragraph (b)(8)(i) and adding paragraph (b)(8)(ii);

■ e. Redesignating paragraph (b)(9) as paragraph (b)(9)(i) and adding paragraph (b)(9)(ii); and

■ f. In paragraphs (b)(12), (b)(13), and (b)(20), removing ''through 2022'' and adding in its place ''and thereafter''.

The additions read as follows:

§ 97.810 State NO_X Ozone Season Group 2 trading budgets, new unit set-asides, Indian country new unit set-asides, and variability limits.

(a) * * *

(8) * * *

(iv) The NO_X Ozone Season Group 2 trading budget for 2023 and thereafter is 14,051 tons.

(v) The new unit set-aside for 2023 and thereafter is 283 tons.

(vi) [Reserved]

(9) * * *

(iv) The NO_X Ozone Season Group 2 trading budget for 2023 and thereafter is 14,818 tons.

(v) The new unit set-aside for 2023 and thereafter is 430 tons.

(vi) The Indian country new unit set-aside for 2023 and thereafter is 15 tons.

* * * * *

(b) * * *

(8) * * *

(ii) The variability limit for Kentucky for 2023 and thereafter is 2,951 tons.

(9) * * *

(ii) The variability limit for Louisiana for 2023 and thereafter is 3,112 tons.

* * * * *

■ 17. Amend § 97.811 by:

■ a. Revising paragraph (a)(2);

■ b. In paragraphs (d)(1), (d)(2)(i), (d)(2)(ii)(A) through (C), (d)(3)(i) through (iii), (d)(3)(iv)(A) through (C), (d)(3)(v)(B) and (C), (d)(4)(i) through (iii), (d)(5) introductory text, (d)(5)(i) and (ii), and (d)(6), adding ''Original'' before ''Group 2'' each time it appears;

■ c. In paragraph (e)(1):

■ i. Adding ''and not listed in § 52.38(b)(2)(ii)(D)(*2*) of this chapter'' before ''(and Indian country''; and

■ ii. Adding ''Original'' before ''Group 2'' each time it appears; and

■ d. In paragraphs (e)(2)(i), (e)(2)(ii)(A) through (C), (e)(3)(i) through (iii), (e)(3)(iv)(A) through (C), (e)(3)(v)(B) and (C), (e)(4)(i) through (iii), (e)(5) introductory text, (e)(5)(i) and (ii), and (e)(6), adding ''Original'' before ''Group 2'' each time it appears.

The revision reads as follows:

§ 97.811 Timing requirements for CSAPR NO_X Ozone Season Group 2 allowance allocations.

(a) * * *

(2) Notwithstanding paragraph (a)(1) of this section:

(i) If a unit provided an allocation of CSAPR NO_X Ozone Season Original Group 2 allowances in the applicable notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2016, during the control period in two consecutive years, such unit will not be allocated the CSAPR NO_X Ozone Season Original Group 2 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year.

(ii) If a unit provided an allocation of CSAPR NO_X Ozone Season Expanded Group 2 allowances in the applicable notice of data availability issued under paragraph (a)(1) of this section does not operate, starting after 2020, during the control period in two consecutive years, such unit will not be allocated the CSAPR NO_X Ozone Season Expanded Group 2 allowances provided in such notice for the unit for the control periods in the fifth year after the first such year and in each year after that fifth year.

(iii) All CSAPR NO_X Ozone Season Group 2 allowances that would otherwise have been allocated to a unit described in paragraph (a)(2)(i) or (ii) of this section will be allocated to the new unit set-aside for the State where such unit is located and for the respective years involved. If such unit resumes operation, the Administrator will allocate CSAPR NO_X Ozone Season Group 2 allowances to the unit in accordance with paragraph (b) of this section.

* * * * *

■ 18. Amend § 97.816 by revising paragraph (c) to read as follows:

§ 97.816 Certificate of representation.

* * * * *

(c) A certificate of representation under this section, § 97.516, or § 97.1016 that complies with the provisions of paragraph (a) of this section except that it contains the phrase ''TR NO_X Ozone Season'' or the phrase ''CSAPR NO_X Ozone Season Group 3'' in place of the phrase ''CSAPR NO_X Ozone Season Group 2'' in the required certification statements will be considered a complete certificate of representation under this section, and the certification statements included in such certificate of representation will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 2'' appeared in place of the phrase ''TR NO_X Ozone Season'' or the phrase ''CSAPR NO_X Ozone Season Group 3''.

■ 19. Amend § 97.818 by redesignating paragraph (f) as paragraph (f)(1) and adding paragraph (f)(2) to read as follows:

§ 97.818 Delegation by designated representative and alternate designated representative.

* * * * *

(f) * * *

(2) A notice of delegation submitted under paragraph (c) of this section or § 97.1018(c) that complies with the provisions of paragraph (c) of this section except that it contains the terms ''40 CFR 97.1018(d)'' and ''40 CFR 97.1018'' in place of the terms ''40 CFR 97.818(d)'' and ''40 CFR 97.818'', respectively, in the required certification statements will be considered a valid notice of delegation submitted under paragraph (c) of this section, and the certification statements included in such notice of delegation will be interpreted for purposes of this subpart as if the terms ''40 CFR 97.818(d)'' and ''40 CFR 97.818'' appeared in place of the terms ''40 CFR 97.1018(d)'' and ''40 CFR 97.1018'', respectively.

■ 20. Amend § 97.820 by:

■ a. Revising paragraphs (c)(1)(iv) and (c)(2)(iv); and

■ b. Redesignating paragraph (c)(5)(vi) as paragraph (c)(5)(vi)(A) and adding paragraph (c)(5)(vi)(B).

The revisions and addition read as follows:

§ 97.820 Establishment of compliance accounts, assurance accounts, and general accounts.

* * * * *

(c) * * *

(1) * * *

(iv) An application for a general account under paragraph (c)(1) of this section, § 97.520(c)(1), or § 97.1020(c)(1) that complies with the provisions of paragraph (c)(1) of this section except that it contains the phrase ''TR NO_X Ozone Season'' or the phrase ''CSAPR NO_X Ozone Season Group 3'' in place of the phrase ''CSAPR NO_X Ozone Season Group 2'' in the required certification statement will be considered a complete application for a general account under paragraph (c)(1) of this section, and the certification statement included in such application for a general account will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 2'' appeared in place of the phrase ''TR NO_X Ozone Season'' or the phrase ''CSAPR NO_X Ozone Season Group 3''.

(2) * * *

(iv) A certification statement submitted in accordance with paragraph (c)(2)(ii) of this section that contains the phrase ''TR NO_X Ozone Season'' or the phrase ''CSAPR NO_X Ozone Season Group 3'' will be interpreted for purposes of this subpart as if the phrase ''CSAPR NO_X Ozone Season Group 2'' appeared in place of the phrase ''TR NO_X Ozone Season'' or the phrase ''CSAPR NO_X Ozone Season Group 3''.

* * * * *

(5) * * *

(vi) * * *

(B) A notice of delegation submitted under paragraph (c)(5)(iii) of this section or § 97.1020(c)(5)(iii) that complies with the provisions of paragraph (c)(5)(iii) of this section except that it contains the terms ''40 CFR 97.1020(c)(5)(iv)'' and ''40 CFR 97.1020(c)(5)'' in place of the terms ''40 CFR 97.820(c)(5)(iv)'' and ''40 CFR 97.820(c)(5)'', respectively, in the required certification statements will be considered a valid notice of delegation submitted under paragraph (c)(5)(iii) of this section, and the certification statements included in such notice of delegation will be interpreted for purposes of this subpart as if the terms ''40 CFR 97.820(c)(5)(iv)'' and ''40 CFR 97.820(c)(5)'' appeared in place of the terms ''40 CFR 97.1020(c)(5)(iv)'' and ''40 CFR 97.1020(c)(5)'', respectively.

* * * * *

■ 21. Amend § 97.821 by:
■ a. Redesignating paragraph (e) as paragraph (e)(1);
■ b. In newly redesignated paragraph (e)(1), adding ''Original'' before ''Group 2 allowances'' each time it appears; and
■ c. Adding paragraph (e)(2).

The addition reads as follows:

§ 97.821 Recordation of CSAPR NO_X Ozone Season Group 2 allowance allocations and auction results.

* * * * *

(e) * * *

(2) By September 5, 2023, the Administrator will record in each CSAPR NO_X Ozone Season Group 2 source's compliance account the CSAPR NO_X Ozone Season Expanded Group 2 allowances allocated to the CSAPR NO_X Ozone Season Group 2 units at the source in accordance with § 97.811(a) for the control periods in 2023 and 2024.

* * * * *

■ 22. Amend § 97.824 by:
■ a. In paragraph (a)(1), removing ''and'' after the semicolon;
■ b. Adding paragraphs (a)(3) and (4);
■ c. In paragraph (c)(2)(ii), removing ''§ 97.526(d), in'' and adding in its place ''§ 97.526(d), § 97.826(d), or § 97.1026(e), in''; and
■ d. Revising paragraph (d).

The additions and revision read as follows:

§ 97.824 Compliance with CSAPR NO_X Ozone Season Group 2 emissions limitation.

(a) * * *

(3) Are CSAPR NO_X Ozone Season Original Group 2 allowances, if the deductions are not for compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation of a source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) for a control period after 2022; and

(4) Are CSAPR NO_X Ozone Season Expanded Group 2 allowances, if the deductions are for compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation of a source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) for a control period after 2022.

* * * * *

(d) *Deductions for excess emissions.* After making the deductions for compliance under paragraph (b) of this section for a control period in a year in which the CSAPR NO_X Ozone Season Group 2 source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CSAPR NO_X Ozone Season Group 2 allowances, allocated or auctioned for a control period in a prior year or the control period in the year of the excess emissions or in the immediately following year, equal to two times the number of tons of the source's excess emissions, provided that—

(1) The allowances deducted shall be CSAPR NO_X Ozone Season Original Group 2 allowances, if the excess emissions are not from a source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) for a control period after 2022; and

(2) The allowances deducted shall be CSAPR NO_X Ozone Season Expanded Group 2 allowances, if the excess emissions are from a source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) for a control period after 2022.

* * * * *

■ 23. Amend § 97.825 by:
■ a. In paragraph (a)(1), removing ''and'' after the semicolon; and
■ b. Adding paragraphs (a)(3) and (4).

The additions read as follows:

§ 97.825 Compliance with CSAPR NO_X Ozone Season Group 2 assurance provisions.

(a) * * *

(3) Are CSAPR NO_X Ozone Season Original Group 2 allowances, if the deductions are not for compliance with the CSAPR NO_X Ozone Season Group 2 assurance provisions by the owners and operators of a group of sources in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) for a control period after 2022; and

(4) Are CSAPR NO_X Ozone Season Expanded Group 2 allowances, if the deductions are for compliance with the CSAPR NO_X Ozone Season Group 2 assurance provisions by the owners and operators of a group of sources in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) for a control period after 2022.

* * * * *

■ 24. Amend § 97.826 by:
■ a. In paragraphs (d)(1)(i)(A) and (D), (d)(1)(ii)(A), (d)(1)(iii)(A), (d)(1)(iv)(A) and (B), and (d)(2)(ii), adding ''Original'' before ''Group 2 allowances'' each time it appears;
■ b. Redesignating paragraph (d)(3) as paragraph (d)(3)(i);
■ c. In newly redesignated paragraph (d)(3)(i):
■ i. Removing ''After the Administrator'' and adding in its place ''Except as provided in paragraph (d)(3)(ii) of this section, after the Administrator''; and
■ ii. Adding ''Original'' before ''Group 2 allowances'' each time it appears;
■ d. Adding paragraph (d)(3)(ii);
■ e. In paragraph (e)(1) introductory text, adding ''or (D)'' before ''of this chapter'';
■ f. In paragraphs (e)(1)(i), (e)(1)(ii)(A), (e)(1)(iii) and (iv), (e)(1)(v)(B), and (e)(2), adding ''Original'' before ''Group 2 allowances'' each time it appears;
■ g. Revising paragraph (f) introductory text;
■ h. Redesignating paragraph (f)(1) as paragraph (f)(1)(i);
■ i. In newly redesignated paragraph (f)(1)(i):
■ i. Removing ''After the Administrator'' and adding in its place ''Except as provided in paragraph (f)(1)(ii) of this section, after the Administrator''; and
■ ii. Adding ''Original'' before ''Group 2 allowances'' each time it appears;
■ j. Adding paragraph (f)(1)(ii); and
■ k. In paragraph (f)(2):
■ i. Adding ''and not listed in § 52.38(b)(ii)(D)(*2*) of this chapter'' before ''(and Indian country''; and
■ ii. Adding ''Original'' before ''Group 2 allowances'' each time it appears.

The additions and revision read as follows:

§ 97.826 Banking and conversion.

* * * * *

(d) * * *

(3) * * *

(ii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.1026(e), upon any determination that would otherwise result in the initial recordation of a given number of CSAPR NO_X Ozone Season Original Group 2 allowances in the compliance account for a source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State), the Administrator will not record such CSAPR NO_X Ozone Season Original Group 2 allowances but instead will allocate and record in such account an amount of CSAPR NO_X Ozone Season Expanded Group 2 allowances for the control period in 2023 computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Original Group 2 allowances divided by the conversion factor determined under paragraph (d)(1)(i)(D) of this section.

* * * * *

(f) Notwithstanding any other provision of this subpart or any SIP revision approved under § 52.38(b)(8) or (9) of this chapter, CSAPR NO_X Ozone Season Expanded Group 2 allowances or CSAPR NO_X Ozone Season Group 3 allowances may be used to satisfy requirements to hold CSAPR NO_X Ozone Season Original Group 2 allowances under this subpart as follows, provided that nothing in this paragraph (f) alters the time as of which any such allowance holding requirement must be met or limits any consequence of a failure to timely meet any such allowance holding requirement:

(1) * * *

(ii) After the Administrator has carried out the procedures set forth in paragraph (d)(1) of this section and § 97.1026(e), the owner or operator of a CSAPR NO_X Ozone Season Group 2 source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Original Group 2 allowances for a control period in 2017 through 2020 by holding instead, in a general account established for this sole purpose, an amount of CSAPR NO_X Ozone Season Expanded Group 2 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.802 has passed) computed as the quotient, rounded up to the nearest allowance, of such given number of CSAPR NO_X Ozone Season Original Group 2 allowances divided by the conversion factor determined under paragraph (d)(1)(i)(D) of this section.

* * * * *

■ 25. Amend § 97.830 by revising paragraph (b)(1) to read as follows:

§ 97.830 General monitoring, recordkeeping, and reporting requirements.

* * * * *

(b) * * *

(1)(i) May 1, 2017, for a unit other than a unit described in paragraph (b)(1)(ii) of this section;

(ii) May 1, 2023, for a unit that did not commence commercial operation at least 180 calendar days before September 30, 2020 and that is located in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State);

* * * * *

■ 26. Amend § 97.834 by revising paragraph (d)(2)(i) to read as follows:

§ 97.834 Recordkeeping and reporting.

* * * * *

(d) * * *

(2) * * *

(i)(A) The calendar quarter covering May 1, 2017 through June 30, 2017, for a unit other than a unit described in paragraph (d)(2)(i)(B) of this section;

(B) The calendar quarter covering May 1, 2023 through June 30, 2023, for a unit that did not commence commercial operation at least 180 calendar days before September 30, 2020 and that is located in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State);

* * * * *

Subpart GGGGG—CSAPR NO_X Ozone Season Group 3 Trading Program

■ 27. Amend § 97.1002 by:

■ a. Adding in alphabetical order a definition of ''CSAPR NO_X Ozone Season Expanded Group 2 allowance'';

■ b. Revising the definition of ''CSAPR NO_X Ozone Season Group 2 allowance''; and

■ c. Adding in alphabetical order a definition of ''CSAPR NO_X Ozone Season Original Group 2 allowance''.

The additions and revision read as follows:

§ 97.1002 Definitions.

* * * * *

CSAPR NO_X Ozone Season Expanded Group 2 allowance means a CSAPR NO_X Ozone Season Group 2 allowance allocated for a control period after 2022 under subpart EEEEE of this part, § 97.526(d), or § 97.1026(e) to a unit in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) or allocated or auctioned for a control period after 2022 in accordance with the provisions of a SIP revision approved for such a State by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter.

* * * * *

CSAPR NO_X Ozone Season Group 2 allowance means a limited authorization issued and allocated or auctioned by the Administrator under subpart EEEEE of this part, § 97.526(d), or § 97.1026(e), or by a State or permitting authority under a SIP revision approved by the Administrator under § 52.38(b)(7), (8), or (9) of this chapter, to emit one ton of NO_X during a control period of the specified calendar year for which the authorization is allocated or auctioned or of any calendar year thereafter under the CSAPR NO_X Ozone Season Group 2 Trading Program, where each CSAPR NO_X Ozone Season Group 2 allowance is either a CSAPR NO_X Ozone Season Original Group 2 allowance or a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

CSAPR NO_X Ozone Season Original Group 2 allowance means a CSAPR NO_X Ozone Season Group 2 allowance other than a CSAPR NO_X Ozone Season Expanded Group 2 allowance.

* * * * *

■ 28. Amend § 97.1026 by:

■ a. Revising the section heading; and

■ b. Adding paragraphs (e) and (f).

The revision and additions read as follows:

§ 97.1026 Banking and conversion; bank recalibration.

* * * * *

(e) Notwithstanding any other provision of this subpart, by September 18, 2023, the Administrator will temporarily suspend acceptance of CSAPR NO_X Ozone Season Group 3 allowance transfers submitted under § 97.1022 and, before resuming acceptance of such transfers, will take the actions in paragraphs (e)(1) and (2) of this section with regard to every compliance account for a CSAPR NO_X Ozone Season Group 3 source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State):

(1) The Administrator will deduct all CSAPR NO_X Ozone Season Group 3 allowances allocated for the control periods in 2021 and 2022 from each such compliance account.

(2) For each CSAPR NO_X Ozone Season Group 3 allowance deducted from a given source's compliance account under paragraph (e)(1) of this section, the Administrator will allocate to the source and record in the source's compliance account one CSAPR NO_X Ozone Season Expanded Group 2 allowance for the control period in 2023.

(f) Notwithstanding any other provision of this subpart, CSAPR NO_X Ozone Season Expanded Group 2 allowances may be used to satisfy requirements to hold CSAPR NO_X Ozone Season Group 3 allowances under this subpart as follows, provided that nothing in this paragraph (f) alters the time as of which any such allowance holding requirement must be met or limits any consequence of a failure to timely meet any such allowance holding requirement:

(1) After the Administrator has carried out the procedures set forth in paragraph (e) of this section, the owner or operator of a CSAPR NO_X Ozone Season Group 3 source in a State listed in § 52.38(b)(2)(ii)(D)(*1*) of this chapter (and Indian country within the borders of such a State) may satisfy a requirement to hold a given number of CSAPR NO_X Ozone Season Group 3 allowances for the control period in 2021 or 2022 by holding instead, in a general account established for this sole purpose, an equal amount of CSAPR NO_X Ozone Season Expanded Group 2 allowances for the control period in 2023 (or any later control period for which the allowance transfer deadline defined in § 97.802 has passed).

(2) [Reserved]

■ 29. Amend § 97.1034 by:

■ a. In paragraph (d)(2)(i)(C), removing ''June'' and adding in its place ''September'';

■ b. In paragraph (d)(3), revising the first sentence; and

■ c. In paragraph (d)(4), adding a second sentence.

The revision and addition read as follows:

§ 97.1034 Recordkeeping and reporting.

* * * * *

(d) * * *

(3) The designated representative shall submit each quarterly report to the Administrator within 30 days after the end of the calendar quarter covered by the report, except that quarterly reports required for the calendar quarter covering May 1, 2023, through June 30, 2023, shall be submitted by August 4, 2023. * * *

(4) * * * Notwithstanding the provisions of §§ 75.64(a), 75.73(f)(1), 97.434(d)(2), 97.634(d)(2), and 97.734(d)(2), the deadline for the designated representative of such a unit to submit the quarterly reports required under such additional programs for the calendar quarter covering May 1, 2023, through June 30, 2023, shall be August 4, 2023.

* * * * *

[FR Doc. 2023–14180 Filed 7–28–23; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

42 CFR Part 414

[CMS–5538–N]

Medicare Program; Alternative Payment Model (APM) Incentive Payment Advisory for Clinicians—Request for Current Billing Information for Qualifying APM Participants

AGENCY: Centers for Medicare & Medicaid Services (CMS), Health and Human Services (HHS).

ACTION: Payment advisory.

SUMMARY: This advisory is to alert certain clinicians who are Qualifying APM participants (QPs) and eligible to receive an Alternative Payment Model (APM) Incentive Payment that CMS does not have the current billing information needed to disburse the payment. This advisory provides information to these clinicians on how to update their billing information to receive this payment.

DATES: Updated billing information must be received no later than September 1, 2023 (see **SUPPLEMENTARY INFORMATION** for details).

FOR FURTHER INFORMATION CONTACT: Tanya Dorm, (410) 786–2216.

SUPPLEMENTARY INFORMATION:

I. Background

Under the Medicare Quality Payment Program, an eligible clinician who participates in an Advanced Alternative Payment Model (APM) and meets the applicable payment amount or patient count thresholds for a performance year is a Qualifying APM Participant (QP) for that year. For payment years 2019 through 2024, which corresponds to Performance Periods for 2017 through 2022, an eligible clinician who is a QP for a year based on their performance in a QP Performance Period earns a 5 percent lump sum APM Incentive Payment that is paid in a payment year that occurs 2 years after the QP Performance Period. The amount of the APM Incentive Payment is equal to 5 percent of the estimated aggregate paid amounts for covered professional services furnished by the QP during the calendar year immediately preceding the payment year.

II. Provisions of the Advisory

The Centers for Medicare & Medicaid Services (CMS) has identified those eligible clinicians who earned an APM Incentive Payment for the calendar year (CY) 2023 payment year based on their QP status for the 2021 QP performance period.

When CMS disbursed the CY 2023 APM Incentive Payments, CMS was unable to verify current Medicare billing information for some QPs and was therefore unable to issue payment. In order to successfully disburse the APM Incentive Payment, CMS is requesting assistance in identifying current Medicare billing information for these QPs in accordance with 42 CFR 414.1450(c)(8).

CMS has compiled a list of QPs we have identified as having unverified billing information. These QPs, and any others who anticipated receiving an APM Incentive Payment but have not, should follow the instructions to provide CMS with updated billing information at the following web address: *https://qpp.cms.gov/resources/resource-library.*

If you have any questions concerning submission of information through the website, please contact the Quality Payment Program Help Desk at 1–866–288–8292.

All submissions must be received no later than September 1, 2023. After that time, any claims to an APM Incentive Payment for the CY 2023 payment period based on an eligible clinicians' QP status for the 2021 QP performance period will be forfeited.

All submissions received by September 1, 2023, will be processed together on one date as soon as practicable after September 1, 2023. CMS will not notify the submitter if we are unable to process the APM Incentive Payment based on the billing information submitted for an eligible clinician.

The Administrator of the Centers for Medicare & Medicaid Services (CMS), Chiquita Brooks-LaSure, having reviewed and approved this document, authorizes Evell J. Barco Holland, who is the Federal Register Liaison, to electronically sign this document for purposes of publication in the **Federal Register**.

Dated: July 25, 2023.

Evell J. Barco Holland,

Federal Register Liaison, Centers for Medicare & Medicaid Services.

[FR Doc. 2023–16140 Filed 7–28–23; 8:45 am]

BILLING CODE 4120–01–P

Motion to Stay, *United States Steel Corporation v. EPA, et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit I

Notice of Forthcoming EPA Action to Address Additional Stay Orders (Aug. 2, 2023)

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

August 2, 2023

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Notice of Forthcoming EPA Action to Address Additional Judicial Stay Orders

FROM: Joseph Goffman
Principal Deputy Assistant Administrator
Office of Air and Radiation

On February 13, 2023, EPA published a final action fully or partially disapproving state implementation plans (SIPs) submitted by 21 states to address the states' obligations under Clean Air Act section 110(a)(2)(D)(i)(I), commonly referred to as the "good neighbor" provision, with respect to the 2015 national ambient air quality standards (NAAQS) for ozone (the SIP Disapproval Action).[1] Consistent with EPA's obligation under Clean Air Act section 110(c)(1), following the SIP Disapproval action the EPA Administrator signed a separate final action, the "Good Neighbor Plan," establishing federal implementation plan requirements to address the states' good neighbor obligations.[2] The Good Neighbor Plan's requirements are scheduled to take effect on August 4, 2023, 60 days after the date of that rule's publication in the *Federal Register*.

After signature of the Good Neighbor Plan, courts granted motions for partial stays of the SIP Disapproval Action with respect to several states. To comply with those orders, on June 29, 2023, the EPA Administrator signed another final action: the Interim Final Rule.[3] In compliance with the courts' decisions, this rule stays the effectiveness of the Good Neighbor Plan's requirements on an interim basis for emissions sources in Arkansas, Kentucky, Louisiana, Mississippi, Missouri, and Texas. This rule also ensures continued implementation of previously established requirements for sources in these states to mitigate interstate air pollution with respect to other ozone NAAQS while the Good Neighbor Plan's requirements are stayed.

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[1] Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336 (February 13, 2023).
[2] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 FR 36654 (June 5, 2023).
[3] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 FR 49295 (July 31, 2023).

Since signature of the Interim Final Rule, courts have granted additional motions for partial stays of the SIP Disapproval Action as to Minnesota,[4] Nevada,[5] Oklahoma, and Utah.[6] To comply with these additional orders, EPA will take action in the near future to extend the Interim Final Rule to stay the effectiveness of the Good Neighbor Plan's requirements for sources in Minnesota, Nevada, Oklahoma, and Utah while the orders partially staying the SIP Disapproval Action with respect to these states remain in place, and sources in these states are not required to comply with the Good Neighbor Plan at this time.

Motions for partial stays of the SIP Disapproval Action regarding additional states remain pending in other courts. If those courts grant such motions, EPA will extend the Interim Final Rule to ensure that the Good Neighbor Plan's requirements are not effective for sources in any additional state where EPA lacks federal implementation authority because of a stay order, and sources in such states would likewise not be required to comply with the Good Neighbor Plan.

EPA plans to take action extending the Interim Final Rule once all pending motions for partial stays are resolved. This action will make clear that the status quo is maintained as to all such states. To the extent that sources in a given state are covered by previously established requirements to mitigate interstate air pollution with respect to other ozone NAAQS, EPA also intends to apply the provisions of the Interim Final Rule to the sources as needed to ensure that implementation of the previously established requirements continues while the effectiveness of the Good Neighbor Plan's requirements is stayed.

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[4] Unpublished Order, *Allete, Inc. v. EPA*, No. 23-1776 (8th Cir. July 5, 2023) (staying SIP Disapproval Action as to Minnesota).

[5] Unpublished Order, *Nevada Cement Co. v. EPA*, No. 23-682 (9th Cir. July 3, 2023) (staying SIP Disapproval Action as to Nevada).

[6] Unpublished Order, *Utah v. EPA*, No. 23-9509, *PacifiCorp v. EPA*, No. 23-9512, *Utah Associated Municipal Power Systems v. EPA*, No. 23-9520, *Oklahoma v. EPA*, No. 23-9514, and *Oklahoma Gas & Electric Co. v. EPA*, No. 23-9521 (10th Cir. July 31, 2023) (staying SIP Disapproval Action as to Oklahoma and Utah).

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit J

Air Plan Approval; Wyoming; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 54,998 (Aug. 14, 2023)

IV. Incorporation by Reference

In this rule, EPA is proposing to include in a final EPA rule regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, EPA is proposing to incorporate by reference certain provisions of the Ohio Division of Air Pollution Control Permit-to-Install and Operate for Forest City Technologies Plant 4, effective June 23, 2020, as described in Section III. of this preamble. EPA has made, and will continue to make, these documents generally available through *www.regulations.gov* and at the EPA Region 5 Office (please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section of this preamble for more information).

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the CAA and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely approves state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993), 13563 (76 FR 3821, January 21, 2011), and 14094 (88 FR 21879, April 11, 2023);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it approves a state program;
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001); and
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA.

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have Tribal implications and will not impose substantial direct costs on Tribal governments or preempt Tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

Executive Order 12898 (Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 FR 7629, February 16, 1994) directs Federal agencies to identify and address ''disproportionately high and adverse human health or environmental effects'' of their actions on minority populations and low-income populations to the greatest extent practicable and permitted by law. EPA defines environmental justice (EJ) as ''the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.'' EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.''

OEPA did not evaluate environmental justice considerations as part of its SIP submittal; the CAA and applicable implementing regulations neither prohibit nor require such an evaluation. EPA did not perform an EJ analysis and did not consider EJ in this action. Consideration of EJ is not required as part of this action, and there is no information in the record inconsistent with the stated goal of E.O. 12898 of achieving environmental justice for people of color, low-income populations, and Indigenous peoples.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements, Volatile organic compounds.

Dated: August 8, 2023.

Debra Shore,

Regional Administrator, Region 5.

[FR Doc. 2023–17337 Filed 8–11–23; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2023–0375; EPA–HQ–OAR–2021–0663; FRL–11233–01–R8]

Air Plan Approval; Wyoming; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule and withdrawal of proposed rule.

SUMMARY: Pursuant to the Federal Clean Air Act (CAA or the Act), the Environmental Protection Agency (EPA) is proposing to approve the portion of a Wyoming State Implementation Plan (SIP) submission addressing interstate transport for the 2015 8-hour ozone national ambient air quality standards (NAAQS). EPA is also withdrawing our prior May 24, 2022 proposed disapproval of the interstate transport portion of the Wyoming SIP submission. The ''good neighbor'' or ''interstate transport'' provision requires that each state's SIP contain adequate provisions to prohibit emissions from within the state from significantly contributing to nonattainment or interfering with maintenance of the NAAQS in other states. This requirement is part of the broader set of ''infrastructure'' requirements, which are designed to ensure that the structural components of each state's air quality management program are adequate to meet the state's responsibilities under the CAA.

DATES: Written comments must be received on or before September 13, 2023. As of August 14, 2023, the proposed rule published on May 24, 2022, at 87 FR 31495, is withdrawn.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2023–0375, to the Federal Rulemaking Portal: *https://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *www.regulations.gov.* EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www2.epa.gov/dockets/commenting-epa-dockets.*

Docket: There are two dockets supporting this action, EPA–R08–OAR–2023–0375 and EPA–HQ–OAR–2021–0663. Docket No. EPA–R08–OAR–2023–0375 contains information specific to Wyoming, including the notice of proposed rulemaking. Docket No. EPA–HQ–OAR–2021–0663 contains additional modeling files, emissions inventory files, technical support documents, and other relevant supporting documentation regarding interstate transport of emissions for the 2015 8-hour ozone NAAQS which are being used to support this action. All comments regarding information in either of these dockets are to be made in Docket No. EPA–R08–OAR–2023–0375. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available electronically in *www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT:
Adam Clark, Air and Radiation Division, EPA, Region 8, Mailcode 8ARD–IO, 1595 Wynkoop Street, Denver, Colorado 80202–1129, telephone number: (303) 312–7104, email address: *clark.adam@epa.gov.*

SUPPLEMENTARY INFORMATION:
Throughout this document whenever ''we,'' ''us,'' or ''our'' is used, we mean EPA.

Table of Contents

I. Background

A. Description of Statutory Background

On October 1, 2015, EPA promulgated a revision to the ozone NAAQS (2015 8-hour ozone NAAQS), lowering the level of both the primary and secondary standards to 0.070 parts per million (ppm) for the 8-hour standard.[1] Section 110(a)(1) of the CAA requires states to submit, within 3 years after promulgation of a new or revised standard, SIP submissions meeting the applicable requirements of section 110(a)(2).[2] One of these applicable requirements is found in CAA section 110(a)(2)(D)(i)(I), otherwise known as the ''interstate transport'' or ''good neighbor'' provision, which generally requires SIPs to contain adequate provisions to prohibit in-state emissions activities from having certain adverse air quality effects on other states due to interstate transport of pollution. There are two so-called ''prongs'' within CAA section 110(a)(2)(D)(i)(I). A SIP for a new or revised NAAQS must contain adequate provisions prohibiting any source or other type of emissions activity within the state from emitting air pollutants in amounts that will significantly contribute to nonattainment of the NAAQS in another state (prong 1) or interfere with maintenance of the NAAQS in another state (prong 2). EPA and states must give independent significance to prong 1 and prong 2 when evaluating downwind air quality problems under CAA section 110(a)(2)(D)(i)(I).[3]

B. Description of EPA's 4-Step Interstate Transport Regulatory Process

EPA is using the 4-step interstate transport framework (or 4-step framework) to evaluate Wyoming's January 3, 2019 SIP submission addressing interstate transport for the 2015 ozone NAAQS. EPA has addressed the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) with respect to prior NAAQS in several regulatory actions, including the Cross-State Air Pollution Rule (CSAPR), which addressed interstate transport with respect to the 1997 ozone NAAQS as well as the 1997 and 2006 fine particulate matter standards,[4] the Cross-State Air Pollution Rule Update (CSAPR Update)[5] and the Revised Cross-State Air Pollution Rule Update (Revised CSAPR Update),[6] both of which addressed the 2008 ozone NAAQS.[7]

Shaped through the years by input from state air agencies[8] and other stakeholders on EPA's prior interstate transport rulemakings and SIP actions,[9] as well as a number of court decisions, EPA has developed and used the following 4-step interstate transport framework to evaluate a state's obligations to eliminate interstate transport emissions under the interstate transport provision for the ozone NAAQS: (1) identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (*i.e.,* nonattainment and/or maintenance receptors); (2) identify

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[1] National Ambient Air Quality Standards for Ozone, Final Rule, 80 FR 65292 (October 26, 2015). Although the level of the standard is specified in the units of ppm, ozone concentrations are also described in parts per billion (ppb). For example, 0.070 ppm is equivalent to 70 ppb.

[2] SIP revisions that are intended to meet the applicable requirements of section 110(a)(1) and (2) of the CAA are often referred to as infrastructure SIPs and the applicable elements under section 110(a)(2) are referred to as infrastructure requirements.

[3] *See North Carolina* v. *EPA,* 531 F.3d 896, 909–11 (D.C. Cir. 2008).

[4] Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 FR 48208 (Aug. 8, 2011).

[5] Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 81 FR 74504 (Oct. 26, 2016).

[6] Revised Cross-State Air Pollution Rule Update for the 2008 Ozone NAAQS, 86 FR 23054 (April 30, 2021).

[7] In 2019, the D.C. Circuit Court of Appeals remanded the CSAPR Update to the extent it failed to require upwind states to eliminate their significant contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). *Wisconsin* v. *EPA,* 938 F.3d 303, 313 (D.C. Cir. 2019). The Revised CSAPR Update for the 2008 Ozone NAAQS, 86 FR 23054 (April 30, 2021), responded to the remand of the CSAPR Update in *Wisconsin* and the vacatur of a separate rule, the ''CSAPR Close-Out,'' 83 FR 65878 (December 21, 2018), in *New York* v. *EPA,* 781 F. App'x. 4 (D.C. Cir. 2019). The Revised CSAPR Update was upheld in *Midwest Ozone Group* v. *EPA,* 61 F.4th 187 (D.C. Cir. 2023).

[8] *See* 63 FR 57356, 57361 (October 27, 1998).

[9] In addition to CSAPR rulemakings, other regional rulemakings addressing ozone transport include the ''NO_X SIP Call,'' 63 FR 57356 (October 27, 1998), and the ''Clean Air Interstate Rule'' (CAIR), 70 FR 25162 (May 12, 2005).

states that impact those air quality problems in other (*i.e.,* downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis; (3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and (4) adopt permanent and enforceable measures needed to achieve those emissions reductions.

C. Background on EPA's Ozone Transport Modeling Information

In general, EPA has performed nationwide air quality modeling to project ozone design values which are used in combination with measured data to identify nonattainment and maintenance receptors at Step 1. To quantify the contribution of emissions from individual upwind states on 2023 ozone design values for the identified downwind nonattainment and maintenance receptors at Step 2, EPA has performed multiple iterations of nationwide, state-level ozone source apportionment modeling for 2023. The source apportionment modeling projected contributions to ozone at receptors from precursor emissions of anthropogenic nitrogen oxides (NO_X) and volatile organic compounds (VOCs) in individual upwind states.

EPA has released several documents containing projected ozone design values, contributions, and information relevant to air agencies for evaluation of interstate transport with respect to the 2015 ozone NAAQS. First, on January 6, 2017, EPA published a notice of data availability (NODA) in which the Agency requested comment on preliminary interstate ozone transport data including projected ozone design values and interstate contributions for 2023 using a 2011 base year platform.[10] In the NODA, EPA used the year 2023 as the analytic year for this preliminary modeling because this year aligns with the expected attainment year for Moderate ozone nonattainment areas for the 2015 8-hour ozone NAAQS.[11] On October 27, 2017, EPA released a memorandum (October 2017 memorandum) containing updated modeling data for 2023, which incorporated changes made in response to comments on the NODA, and was intended to provide information to assist states' efforts to develop SIP submissions to address interstate transport obligations for the 2008 ozone NAAQS.[12] On March 27, 2018, EPA issued a memorandum (March 2018 memorandum) noting that the same 2023 modeling data released in the October 2017 memorandum could also be useful for identifying potential downwind air quality problems with respect to the 2015 ozone NAAQS at Step 1 of the 4-step interstate transport framework.[13] The March 2018 memorandum also included the then newly available contribution modeling data for 2023 to assist states in evaluating their impact on potential downwind air quality problems for the 2015 8-hour ozone NAAQS under Step 2 of the 4-step interstate transport framework.[14] EPA notes that the State of Wyoming relied upon 2023 modeling contribution data released with the March 2018 memorandum in developing its 2019 SIP submission. EPA subsequently issued two more memoranda in August and October 2018, providing additional information to states developing interstate transport SIP submissions for the 2015 ozone NAAQS concerning, respectively, potential contribution thresholds that may be appropriate to apply in Step 2 of the 4-step interstate transport framework, and considerations for identifying downwind areas that may have problems maintaining the standard at Step 1 of the 4-step interstate transport framework.[15]

Following the release of the modeling data shared in the March 2018 memorandum, EPA performed updated modeling using a 2016-based emissions modeling platform (*i.e.,* 2016v1). This emissions platform was developed under the EPA/Multi-Jurisdictional Organization (MJO)/state collaborative project.[16] This collaborative project was a multi-year joint effort by EPA, MJOs, and states to develop a new, more recent emissions platform for use by EPA and states in regulatory modeling as an improvement over the dated 2011-based platform that EPA had used to project ozone design values and contribution data provided in the 2017 and 2018 memoranda. EPA used the 2016v1 emissions to project ozone design values and contributions for 2023. On October 30, 2020, in the notice of proposed rulemaking for the Revised CSAPR Update, EPA released and accepted public comment on 2023 modeling that used the 2016v1 emissions platform.[17] Although the Revised CSAPR Update addressed transport for the 2008 ozone NAAQS, the projected design values and contributions from the 2016v1 platform were also useful for identifying downwind ozone problems and linkages with respect to the 2015 ozone NAAQS.[18]

Following the final Revised CSAPR Update, EPA made further updates to the 2016-based emissions platform to include updated onroad mobile emissions from Version 3 of EPA's Motor Vehicle Emission Simulator (MOVES) model (MOVES3)[19] and updated emissions projections for electric generating units (EGUs) that reflected the emissions reductions from the Revised CSAPR Update, recent information on plant closures, and other inventory improvements. EPA published these emissions inventories on its website in September of 2021 and invited initial feedback from states and other interested stakeholders.[20] The construct of the updated emissions platform, 2016v2, is described in the

[10] *See* Notice of Availability of the Environmental Protection Agency's Preliminary Interstate Ozone Transport Modeling Data for the 2015 8-hour Ozone National Ambient Air Quality Standard (NAAQS), 82 FR 1733 (January 6, 2017).

[11] 82 FR 1735.

[12] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2008 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), October 27, 2017, available in docket ID No. EPA–HQ–OAR–2021–0663.

[13] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), March 27, 2018 (''March 2018 memorandum''), available in docket ID No. EPA–HQ–OAR–2021–0663.

[14] The March 2018 memorandum, however, provided, ''While the information in this memorandum and the associated air quality analysis data could be used to inform the development of these SIPs, the information is not a final determination regarding states' obligations under the good neighbor provision. Any such determination would be made through notice-and-comment rulemaking.''

[15] *See* Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, August 31, 2018 (''August 2018 memorandum''), and Considerations for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, October 19, 2018, available in docket ID No. EPA–HQ–OAR–2021–0663.

[16] The results of this modeling, as well as the underlying modeling files, are included in docket ID No. EPA–HQ–OAR–2021–0663. The 2016v1 emissions modeling technical support document is available in Docket ID No. EPA–HQ–OAR–2020–0272–0187. Both dockets are available at *https://www.regulations.gov.*

[17] *See* 85 FR 68964, 68981.

[18] See the Air Quality Modeling Technical Support Document for the Final Revised Cross-State Air Pollution Rule Update, included in the Headquarters docket ID No. EPA–HQ–OAR–2021–0663.

[19] Additional details and documentation related to the MOVES3 model can be found at *https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves.*

[20] *https://www.epa.gov/air-emissions-modeling/2016v2-platform.*

''Technical Support Document (TSD): Preparation of Emissions Inventories for the 2016v2 North American Emissions Modeling Platform,'' hereafter known as the 2016v2 Emissions Modeling TSD, and is included in Docket No. EPA–HQ–OAR–2021–0663. The EPA performed air quality modeling using the 2016v2 emissions to provide projections of ozone design values and contributions in 2023 and 2026 that reflect the effects on air quality of the 2016v2 emissions platform. EPA used the results of the 2016v2 modeling as part of our previous proposed evaluation of the Wyoming 2019 SIP submission with respect to Steps 1 and 2 of the 4-step interstate transport framework. *See* 87 FR 31495 (May 24, 2022).

EPA invited and received comments on the 2016v2 emissions inventories and modeling used to support proposals, including the proposal on Wyoming, related to interstate transport under the 2015 ozone NAAQS. In response to these comments, EPA made a number of updates to the 2016v2 inventories and model design to construct a 2016v3 emissions platform which was used to update the air quality modeling. EPA used this updated modeling to inform a final rulemaking taking final action on 21 interstate transport SIP submissions for the 2015 ozone NAAQS, which did not include Wyoming.[21] Details on the 2016v3 air quality modeling and the methods for projecting design values and determining contributions in 2023 and 2026 are described in the TSD titled ''Air Quality Modeling Final Rule TSD—2015 Ozone NAAQS Good Neighbor Plan,'' hereafter known as the Final Good Neighbor Plan AQM TSD.[22] Additional details related to the updated 2016v3 emissions platform are located in the TSD titled ''Preparation of Emissions Inventories for the 2016v3 North American Emissions Modeling Platform,'' hereafter known as the 2016v3 Emissions Modeling TSD, included in Docket ID No. EPA–HQ–OAR–2021–0663.[23]

In this proposed action, EPA primarily relies on modeling based on the updated 2016v3 emissions platform in evaluating Wyoming's 2019 submission with respect to Steps 1 and 2 of the 4-step interstate transport framework, which will generally be referenced within this action as the ''2016v3 modeling'' for 2023 and 2026. By using the updated modeling results, EPA is using the most current and technically appropriate information for this proposed rulemaking. In this proposed action, EPA is accepting public comment on the 2016v3 modeling solely as it relates to Wyoming's interstate transport obligations for the 2015 ozone NAAQS. EPA is not reopening the modeling in relation to any other state or regulatory action. Any comments received on the modeling that are not relevant to the evaluation of Wyoming's interstate-transport obligations will be treated as beyond the scope of this action.

D. EPA's Approach to Evaluating Interstate Transport SIPs for the 2015 Ozone NAAQS

EPA proposes to apply a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submissions for the 2015 ozone NAAQS under CAA section 110(a)(2)(D)(i)(I). These policy judgments conform with relevant case law and past agency practice as reflected in CSAPR and related rulemakings. Employing a nationally consistent approach is particularly important in the context of interstate ozone transport, which is a regional-scale pollution problem involving many smaller contributors. Effective policy solutions to the problem of interstate ozone transport going back to the NO_X SIP Call have necessitated the application of a uniform framework of policy judgments in order to ensure an ''efficient and equitable'' approach. *See EME Homer City Generation, LP* v. *EPA,* 572 U.S. 489, 519 (2014).

The remainder of this section describes EPA's analytic framework with respect to analytic year, definition of nonattainment and maintenance receptors, selection of contribution threshold, and multifactor control strategy assessment.

1. Selection of Analytic Year

In general, the states and EPA must implement the interstate transport provision in a manner ''consistent with the provisions of [title I of the CAA.]'' *See* CAA section 110(a)(2)(D)(i). This requires, among other things, that these obligations are addressed consistently with the timeframes for downwind areas to meet their CAA obligations. With respect to ozone NAAQS, under CAA section 181(a), this means obligations must be addressed ''as expeditiously as practicable'' and no later than the schedule of attainment dates provided in CAA section 181(a)(1).[24] Several D.C. Circuit court decisions address the issue of the relevant analytic year for the purposes of evaluating ozone transport air-quality problems. On September 13, 2019, the D.C. Circuit issued a decision in *Wisconsin,* remanding the CSAPR Update to the extent that it failed to require upwind states to eliminate their significant contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). *See* 938 F.3d 303, 313.

On May 19, 2020, the D.C. Circuit issued a decision in *Maryland* v. *EPA* that cited the *Wisconsin* decision in holding that EPA must assess the impact of interstate transport on air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for EPA's denial of a petition under CAA section 126(b) *Maryland* v. *EPA,* 958 F.3d 1185, 1203–04 (D.C. Cir. 2020) (*Maryland*). The court noted that ''section 126(b) incorporates the Good Neighbor Provision,'' and, therefore, ''EPA must find a violation [of section 126] if an upwind source will significantly contribute to downwind nonattainment at the *next downwind attainment deadline.* Therefore, the agency must evaluate downwind air quality at that deadline, not at some later date.'' *Id.* at 1204 (emphasis added). EPA interprets the court's holding in *Maryland* as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date,[25] which is currently the 2015 ozone NAAQS Moderate area attainment date of August 3, 2024 under CAA section 181 for ozone nonattainment.[26] Thus, 2023 remains

[21] ''Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards,'' 88 FR 9336 (February 13, 2023), and ''Federal ''Good Neighbor Plan'' for the 2015 Ozone National Ambient Air Quality Standards,'' 88 FR 36654 (June 5, 2023).

[22] Air Quality Modeling Final Rule Technical Support Document—2015 Ozone NAAQS Good Neighbor Plan in Docket ID No. EPA–R08–OAR–2023–0375.

[23] 2016v3 Emissions Modeling TSD in Docket ID No. EPA–HQ–OAR–2021–0663.

[24] For attainment dates for the 2015 8-hour ozone NAAQS, refer to CAA section 181(a), 40 CFR 51.1303, and Additional Air Quality Designations for the 2015 Ozone National Ambient Air Quality Standards, 83 FR 25776 (June 4, 2018, effective Aug. 3, 2018).

[25] We note that the court in *Maryland* did not have occasion to evaluate circumstances in which EPA may determine that an upwind linkage to a downwind air quality problem exists at steps 1 and 2 of the interstate transport framework by a particular attainment date, but for reasons of impossibility or profound uncertainty the Agency is unable to mandate upwind pollution controls by that date. *See Wisconsin,* 938 F.3d at 320. The D.C. Circuit noted in *Wisconsin* that upon a sufficient showing, these circumstances may warrant flexibility in effectuating the purpose of the interstate transport provision.

[26] *See* CAA section 181(a); 40 CFR 51.1303; Additional Air Quality Designations for the 2015

Continued

the appropriate year for analysis of interstate transport obligations for the 2015 ozone NAAQS because the 2023 ozone season is the last relevant ozone season during which achieved emissions reductions in linked upwind states could assist downwind states with meeting the August 3, 2024 Moderate area attainment date for the 2015 ozone NAAQS.

EPA recognizes that the attainment date for nonattainment areas classified as Marginal for the 2015 ozone NAAQS was August 3, 2021. Under the *Maryland* holding, any necessary emissions reductions to satisfy interstate transport obligations should have been implemented by no later than this date. At the time of the statutory deadline to submit interstate transport SIPs (October 1, 2018), many states relied on EPA's modeling of the year 2023, and no state provided an alternative analysis using a 2021 analytic year (or the prior 2020 ozone season). However, EPA must act on SIP submissions using the information available at the time it takes such action. In this circumstance, EPA does not believe it would be appropriate to evaluate states' obligations under CAA section 110(a)(2)(D)(i)(I) as of an attainment date that is wholly in the past, because the Agency interprets the interstate transport provision as forward looking. *See* 86 FR 23074; *see also Wisconsin,* 938 F.3d at 322 (rejecting Delaware's argument that EPA should have used an analytic year of 2011 instead of 2017). Consequently, in this proposal EPA will use the analytical year of 2023 to evaluate Wyoming's CAA section 110(a)(2)(D)(i)(I) SIP submission with respect to the 2015 ozone NAAQS.[27]

2. Step 1 of the 4-Step Interstate Transport Framework

In Step 1, EPA identifies monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS in the 2023 analytic year. Where EPA's analysis shows that a site does not fall under the definition of a nonattainment or maintenance receptor, that site is excluded from further analysis under EPA's 4-step interstate transport framework. For sites that are identified as a nonattainment or maintenance receptor in 2023, EPA proceeds to the next step of the 4-step interstate transport framework by identifying which upwind states contribute to those receptors above the contribution threshold.

EPA's approach to identifying ozone nonattainment and maintenance receptors in this action gives independent consideration to both the ''contribute significantly to nonattainment'' and the ''interfere with maintenance'' prongs of CAA section 110(a)(2)(D)(i)(I), consistent with the D.C. Circuit's direction in *North Carolina*.[28]

EPA identifies nonattainment receptors as those monitoring sites that are projected to have average design values that exceed the NAAQS and that are also measuring nonattainment based on the most recent monitored design values. This approach is consistent with prior transport rulemakings, such as the CSAPR Update, where EPA defined nonattainment receptors as those areas that both currently measure nonattainment and that EPA projects will be in nonattainment in the analytic year (*i.e.,* 2023).[29]

In addition, in this proposal, EPA identifies a receptor to be a ''maintenance'' receptor for purposes of defining interference with maintenance, consistent with the method used in CSAPR and upheld by the D.C. Circuit in *EME Homer City Generation, L.P.* v. *EPA,* 795 F.3d 118, 136 (D.C. Cir. 2015) (*EME Homer City II*).[30] Specifically, EPA identified maintenance receptors as those receptors that would have difficulty maintaining the relevant NAAQS in a scenario that takes into account historical variability in air quality at that receptor. The variability in air quality was determined by evaluating the ''maximum'' future design value at each receptor based on a projection of the maximum measured design value over the relevant period. EPA interprets the projected maximum future design value to be a potential future air quality outcome consistent with the meteorology that yielded maximum measured concentrations in the ambient data set analyzed for that receptor (*i.e.,* ozone conducive meteorology). EPA also recognizes that previously experienced meteorological conditions (*e.g.,* dominant wind direction, temperatures, and air mass patterns) promoting ozone formation that led to maximum concentrations in the measured data may reoccur in the future. The maximum design value gives a reasonable projection of future air quality at the receptor under a scenario in which such conditions do, in fact, reoccur. The projected maximum design value is used to identify upwind emissions that, under those circumstances, could interfere with the downwind area's ability to maintain the NAAQS.

Nonattainment receptors are also, by definition, maintenance receptors, and so EPA often uses the term ''maintenance-only'' to refer to those receptors that are not nonattainment receptors. Consistent with the concepts for maintenance receptors, as described earlier, EPA identifies ''maintenance-only'' receptors as those monitoring sites that have projected average design values above the level of the applicable NAAQS, but that are not currently measuring nonattainment based on the most recent official design values.[31] In addition, those monitoring sites with projected average design values below the NAAQS, but with projected maximum design values above the NAAQS are also identified as ''maintenance-only'' receptors, even if they are currently measuring nonattainment based on the most recent official design values.

Ozone National Ambient Air Quality Standards, 83 FR 25776 (June 4, 2018, effective Aug. 3, 2018).

[27] EPA recognizes that by the time final action is taken with respect to this SIP submission, the 2023 ozone season will likely be wholly in the past. However, as discussed in section III., the available modeling information indicates that our analysis would not change as to Wyoming for any later year.

[28] *See North Carolina* v. *EPA,* 531 F.3d at 910–11 (holding that the EPA must give ''independent significance'' to each prong of CAA section 110(a)(2)(D)(i)(I)).

[29] *See* 81 FR 74504 (October 26, 2016). This same concept, relying on both current monitoring data and modeling to define nonattainment receptor, was also applied in CAIR. *See* 70 FR 25241, 25249 (January 14, 2005); *see also North Carolina,* 531 F.3d at 913–14 (affirming as reasonable EPA's approach to defining nonattainment in CAIR).

[30] *See* 76 FR 48208 (August 8, 2011). CSAPR Update and Revised CSAPR Update also used this approach. See 81 FR 74504 (October 26, 2016) and 86 FR 23054 (April 30, 2021).

[31] The Agency often uses the terms maintenance receptor and maintenance-only receptor interchangeably when discussing maintenance receptors that are not also nonattainment receptors.

The Agency has also taken a closer look at measured ozone levels at monitoring sites in 2021 and 2022 for the purposes of informing the identification of additional receptors in 2023. As explained in more detail in the February 13, 2022 final action disapproving 19 states' good neighbor SIP submissions, and partially approving and partially disapproving 2 states' good neighbor SIP submissions, *see* 88 FR 9349–50, we find there is a basis to consider certain sites with elevated ozone levels that are not otherwise identified as receptors to be an additional type of maintenance-only receptor given the likelihood that ozone levels above the NAAQS could persist at those locations through at least 2023. We refer to these as violating-monitor maintenance-only receptors (''violating monitors''). In this action, EPA proposes to use certified monitoring data as an additional method to identify maintenance-only receptors. In the case of Wyoming, this analysis confirms that the state is not projected to be linked to any violating-monitor receptors. EPA is not reopening this methodology, except to the extent of its application to Wyoming, nor in relation to the evaluation of any other state's good neighbor obligations for the 2015 ozone NAAQS. Any such comments on those topics will be treated as beyond the scope of this action.

3. Step 2 of the 4-Step Interstate Transport Framework

In Step 2 EPA quantifies the contribution of each upwind state to each receptor in the 2023 analytic year. The contribution metric used in Step 2 is defined as the average impact from each state to each receptor on the days with the highest ozone concentrations at the receptor based on the 2023 modeling. If a state's contribution value does not equal or exceed the threshold of 1 percent of the NAAQS (*i.e.,* 0.70 ppb for the 2015 ozone NAAQS), the upwind state is not ''linked'' to a downwind air quality problem, and EPA therefore concludes that the state does not contribute significantly to nonattainment or interfere with maintenance of the NAAQS in the downwind states. However, if a state's contribution equals or exceeds the 1 percent threshold, the state's emissions are further evaluated in Step 3, considering both air quality and cost as part of a multi-factor analysis, to determine what, if any, emissions might be deemed ''significant'' and, thus, must be eliminated pursuant to the requirements of CAA section 110(a)(2)(D)(i)(I).

In this proposed action, EPA relies in the first instance on the 1 percent of the NAAQS threshold for the purpose of evaluating a state's contribution to nonattainment or maintenance of the 2015 ozone NAAQS at downwind receptors. This is consistent with the Step 2 approach that EPA applied in CSAPR for the 1997 ozone NAAQS, which has subsequently been applied in the CSAPR Update and Revised CSAPR Update when evaluating interstate transport obligations for the 2008 ozone NAAQS. EPA continues to find 1 percent of the NAAQS to be an appropriate threshold. For ozone, as EPA found in the CAIR, CSAPR, and CSAPR Update, a portion of the nonattainment problems from anthropogenic sources in the U.S. results from the combined impact of relatively small contributions, typically from multiple upwind states and, in some cases, substantially larger contributions from a subset of particular upwind states, along with contributions from in-state sources. EPA's analysis shows that much of the ozone transport problem in the United States is still the result of the collective impacts of contributions from upwind states. Therefore, application of a consistent contribution threshold is necessary to identify those upwind states that should have responsibility for addressing their contribution to the downwind nonattainment and maintenance problems to which they collectively contribute. Continuing to use 1 percent of the NAAQS as the screening metric to evaluate collective contribution from many upwind states also allows EPA (and states) to apply a consistent framework to evaluate interstate emissions transport under the interstate transport provision from one NAAQS to the next. *See* 81 FR 74518*; see also* 86 FR 23085 (reviewing and explaining rationale from CSAPR, 76 FR 48237–38, for selection of 1 percent threshold).

4. Step 3 of the 4-Step Interstate Transport Framework

Consistent with EPA's longstanding approach to eliminating significant contribution and interference with maintenance, at Step 3, a multifactor assessment of potential emissions controls is conducted for states linked at Steps 1 and 2. EPA's analysis at Step 3 in prior Federal actions addressing interstate transport requirements has primarily focused on an evaluation of cost-effectiveness of potential emissions controls (on a marginal cost-per-ton basis), the total emissions reductions that may be achieved by requiring such controls (if applied across all linked upwind states), and an evaluation of the air quality impacts such emissions reductions would have on the downwind receptors to which a state is linked; other factors may potentially be relevant if adequately supported. In general, where EPA's or state-provided alternative air quality and contribution modeling establishes that a state is linked at Steps 1 and 2, it will be insufficient at Step 3 for a state merely to point to its existing rules requiring control measures as a basis for SIP approval. In general, the emissions-reducing effects of all existing emissions control requirements are already reflected in the future year projected air quality results of the modeling for Steps 1 and 2. If the state is shown to still be linked to one or more downwind receptor(s) despite these existing controls, but that state believes it has no outstanding good neighbor obligations, EPA expects the state to provide sufficient justification to support a conclusion by EPA that the state has adequate provisions prohibiting ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will'' ''contribute significantly to nonattainment in, or interfere with maintenance by,'' any other state with respect to the NAAQS. *See* CAA section 110(a)(2)(D)(i)(I). While EPA has not prescribed a particular method for this assessment, EPA expects states at a minimum to present a sufficient technical evaluation. This would typically include information on emissions sources, applicable control technologies, emissions reductions, costs, cost effectiveness, and downwind air quality impacts of the estimated reductions, before concluding that no additional emissions controls should be required.[32]

5. Step 4 of the 4-Step Interstate Transport Framework

At Step 4, states (or EPA) develop permanent and federally-enforceable control strategies to achieve the emissions reductions determined to be necessary at Step 3 to eliminate significant contribution to nonattainment or interference with maintenance of the NAAQS. For a state linked at Steps 1 and 2 to rely on an

[32] As examples of general approaches for how such an analysis could be conducted for their sources, states could look to the CSAPR Update, 81 FR 74504, 74539–51; CSAPR, 76 FR 48208, 48246–63; CAIR, 70 FR 25162, 25195–229; or the NO_X SIP Call, 63 FR 57356, 57399–405. *See also* Revised CSAPR Update, 86 FR 23054, 23086–23116. Consistently across these rulemakings, the EPA has developed emissions inventories, analyzed different levels of control stringency at different cost thresholds, and assessed resulting downwind air quality improvements.

emissions control measure at Step 3 to address its interstate transport obligations, that measure must be included in the state's SIP so that it is permanent and federally enforceable. *See* CAA section 110(a)(2)(D) (''Each such [SIP] shall . . . contain adequate provisions . . . .''). *See also* CAA section 110(a)(2)(A); *Committee for a Better Arvin* v. *EPA,* 786 F.3d 1169, 1175–76 (9th Cir. 2015) (holding that measures relied on by a state to meet CAA requirements must be included in the SIP).

II. Wyoming SIP Submission Addressing Interstate Transport of Air Pollution for the 2015 8-Hour Ozone NAAQS

A. Summary of Wyoming's 2015 Ozone Interstate Transport SIP Submission

On January 3, 2019, Wyoming submitted a SIP submission to EPA addressing the infrastructure requirements of CAA section 110(a)(1) and (2), including the CAA section 110(a)(2)(D)(i)(I) interstate transport requirements, for the 2015 8-hour ozone NAAQS.[33] The SIP submission provided Wyoming's analysis of the State's impact to downwind states and concluded that emissions from Wyoming will not significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in other states in 2023.[34] The SIP submission cited EPA's 4-step framework, but also included a ''weight-of-evidence'' analysis.[35] Based on the results of its ''weight-of-evidence'' analysis at Step 2, Wyoming's 2019 SIP submission concluded that emissions from the State are not linked to a downwind projected nonattainment or maintenance receptor and therefore do not contribute to nonattainment or interfere with the maintenance of the 2015 ozone NAAQS in any downwind state.[36]

B. Prior Notices Related to Wyoming's SIP Submission

On May 24, 2022, the EPA proposed disapproval of the portion of Wyoming's January 3, 2019 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. 87 FR 31495. In EPA's proposed disapproval, as part of the evaluation of Wyoming's submission, we considered the most recently updated modeling platform available at the time, 2016v2, which established one linkage from Wyoming to the Douglas County nonattainment receptor in Colorado (Site ID 80350004), with a projected 2023 contribution from Wyoming of 0.81 ppb.[37] When EPA completed updated modeling for 2023 and 2026 using the 2016v3 platform, Wyoming was not projected to be linked to any downwind nonattainment or maintenance-only receptors in 2023, with a maximum projected contribution of 0.68 ppb at the Douglas County nonattainment receptor in 2023.[38] On January 31, 2023, EPA signed a final rulemaking, finalizing disapproval of 19 SIP submissions, and partially approved and partially disapproved two SIP submissions, for inadequately addressing the good neighbor provision for the 2015 ozone NAAQS and noted that EPA was not taking final action at that time on two SIP submissions for which EPA had proposed disapproval, including Wyoming's.[39] Based on the updated modeling using the 2016v3 platform, discussed in section I.C. above, as well as EPA's evaluation in section III. below, EPA is now withdrawing our May 24, 2022 proposed disapproval of the 110(a)(2)(D)(i)(I) portion of Wyoming's January 3, 2019 SIP submission, at 87 FR 31495.

III. EPA's Evaluation

Wyoming's 2019 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) for the 2015 Ozone NAAQS relies on the 4-step framework and the analytic year 2023 contribution modeling results released with the March 2018 memorandum to conclude that Wyoming does not significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state at Step 2 of the 4-step framework.

As described in section I.C. of this proposal, EPA performed air quality modeling to project ozone design values and contributions for 2023 and 2026 using the 2016v3 emissions platform. EPA proposes to rely primarily on this updated modeling in evaluating Wyoming's transport SIP submission. The design values and contributions from the updated modeling were examined to determine if Wyoming contributes at or above the threshold of 1 percent of the 2015 ozone NAAQS (0.70 ppb) to any downwind nonattainment or maintenance receptor.[40] The data[41] indicate that the highest contributions from Wyoming to downwind nonattainment and maintenance-only receptors are 0.68 ppb and 0.67 ppb in 2023, respectively, and 0.40 ppb and 0.59 ppb in 2026, respectively.[42] EPA's evaluation of Wyoming's contributions to violating-monitor maintenance-only receptors indicate the State's maximum contribution is 0.42 ppb in 2023.[43]

EPA's evaluation of measured and monitored data and contribution values in 2023 and 2026 indicates that the contribution to ozone concentrations in other states from emissions in Wyoming will not equal or exceed the contribution threshold of 0.70 ppb. Thus, EPA proposes to find that the State does not impact downwind air quality problems such that it should be considered ''linked'' at Step 2 of the 4-step framework, and therefore does not warrant further review and analysis at Steps 3 and 4. The results of EPA's evaluation are consistent with the conclusion drawn by Wyoming in the 2019 SIP submission that emissions from sources in Wyoming will not contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state. For these reasons, EPA is proposing to approve Wyoming's 2019 SIP submission with regard to the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I).

IV. Proposed Action

Based on EPA's evaluation of the impact of air emissions from Wyoming

[33] *See* Wyoming State Implementation Plan, Interstate Transport, To Satisfy the Requirements of Clean Air Act 110(a)(2)(i)(I) for the 8-Hour Ozone NAAQS Promulgated in October 2015, December 2018, located in the docket for this rulemaking at *regulations.gov,* Docket No. EPA–R08–OAR–2023–0375.

[34] Wyoming State Implementation Plan, Attachment B at 10.

[35] See generally id. at 3–10.

[36] Id. at 9–10.

[37] 87 FR 31505.

[38] *See* Final Good Neighbor Plan AQM TSD in Docket ID No. EPA–R08–OAR–2023–0375.

[39] *See* Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336 (February 13, 2023).

[40] EPA need not assess the data and analysis in Wyoming's submission, as EPA's updated modeling corroborates Wyoming's conclusion that the State will not significantly contribute to nonattainment or interfere with maintenance of the 2015 ozone NAAQS in any other state.

[41] Design values and contributions at individual monitoring sites nationwide are provided in the file Final GNP O3 DVs Contributions, which is included in docket ID No. EPA–R08–OAR–2023–0375.

[42] EPA's analysis indicates that in 2023 Wyoming will have a 0.68 ppb impact at the projected nonattainment receptor in Douglas County, Colorado (site ID 80350004), and a 0.67 ppb impact at the projected maintenance-only receptor in Larimer County, Colorado (site ID 80690011). EPA's analysis indicates maximum 2026 Wyoming emission impacts of 0.40 ppb at projected nonattainment receptors in Jefferson County, Colorado (sites 80590006 and 80590011), and 0.59 at a projected maintenance receptor in Larimer County, Colorado (site 80690011).

[43] EPA's analysis indicates that in 2023 Wyoming will have a 0.42 ppb impact at the violating-monitor maintenance-only receptor in Arapahoe County, Colorado (site ID 80050002).

to downwind states using 2023 analytic year modeling as described in this document, EPA is proposing to approve Wyoming's January 3, 2019 SIP submission as meeting the interstate transport requirements of CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS. EPA is seeking public comment on the issues discussed in this proposed rule. We will accept comments from the public on this proposal for the next 30 days.

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, the EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a ''significant regulatory action'' subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- Does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- Is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- Does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- Does not have federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- Is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- Is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- Is not subject to requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and

In addition, the SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the proposed rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

Executive Order 12898 (Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations, 59 FR 7629, Feb. 16, 1994) directs Federal agencies to identify and address ''disproportionately high and adverse human health or environmental effects'' of their actions on minority populations and low-income populations to the greatest extent practicable and permitted by law. EPA defines environmental justice (EJ) as ''the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.'' EPA further defines the term fair treatment to mean that ''no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies.'' Wyoming did not evaluate environmental justice considerations as part of its SIP submission; the CAA and applicable implementing regulations neither prohibit nor require such an evaluation. EPA did not perform an EJ analysis and did not consider EJ in this action. Consideration of EJ is not required as part of this action, and there is no information in the record inconsistent with the stated goal of E.O. 12898 of achieving environmental justice for people of color, low-income populations, and Indigenous peoples.

Section 307(b)(1) of the CAA governs judicial review of final actions by EPA. This section provides, in part, that petitions for review must be filed in the D.C. Circuit: (i) when the agency action consists of ''nationally applicable regulations promulgated, or final actions taken, by the Administrator,'' or (ii) when such action is locally or regionally applicable, if ''such action is based on a determination of nationwide scope or effect and if in taking such action the Administrator finds and publishes that such action is based on such a determination.'' For locally or regionally applicable final actions, the CAA reserves to EPA complete discretion to decide whether to invoke the exception in (ii).[44]

If EPA takes final action on this proposed rulemaking, the Administrator intends to exercise the complete discretion afforded to him under the CAA to make and publish a finding that the final action (to the extent a court finds the action to be locally or regionally applicable) is based on a determination of ''nationwide scope or effect'' within the meaning of CAA section 307(b)(1). Through this rulemaking action (in conjunction with a series of related actions on other SIP submissions for the same CAA obligations), EPA interprets and applies section 110(a)(2)(D)(i)(I) of the CAA for the 2015 ozone NAAQS based on a common core of nationwide policy judgments and technical analysis concerning the interstate transport of pollutants throughout the continental U.S. In particular, EPA is applying here (and in other proposed and finalized actions related to the same obligations) the same, nationally consistent 4-step framework for assessing good neighbor obligations for the 2015 ozone NAAQS. EPA relies on a single set of updated, 2016-base year photochemical grid modeling results of the year 2023 as the primary basis for its assessment of air quality conditions and contributions at steps 1 and 2 of that framework. Further, EPA proposes to determine and apply a set of nationally consistent policy judgments to apply the 4-step framework. EPA has selected nationally uniform analytic years for this analysis and is applying a nationally uniform approach to nonattainment and maintenance receptors and a nationally uniform approach to contribution threshold analysis.[45] For these reasons, the Administrator intends, if this proposed action is finalized, to exercise the complete discretion afforded to him under the CAA to make and publish a finding that this action is based on a determination of nationwide scope or

[44] In deciding whether to invoke the exception by making and publishing a finding that an action is based on a determination of nationwide scope or effect, the Administrator takes into account a number of policy considerations, including his judgment balancing the benefit of obtaining the D.C. Circuit's authoritative centralized review versus allowing development of the issue in other contexts and the best use of agency resources.

[45] A finding of nationwide scope or effect is also appropriate for actions that cover states in multiple judicial circuits. In the report on the 1977 Amendments that revised section 307(b)(1) of the CAA, Congress noted that the Administrator's determination that the ''nationwide scope or effect'' exception applies would be appropriate for any action that has a scope or effect beyond a single judicial circuit. *See* H.R. Rep. No. 95–294 at 323, 324, reprinted in 1977 U.S.C.C.A.N. 1402–03.

effect for purposes of CAA section 307(b)(1).[46]

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Ozone.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: July 27, 2023.

K.C. Becker,

Regional Administrator, Region 8.

[FR Doc. 2023–16441 Filed 8–11–23; 8:45 am]

BILLING CODE 6560–50–P

[46] If EPA takes a consolidated, single final action on this and any other proposed SIP actions with respect to obligations under CAA section 110(a)(2)(D)(i)(I) for the 2015 ozone NAAQS, that action may be nationally applicable, and EPA would also anticipate that in that instance, in the alternative, the Administrator would make and publish a finding that such final action is based on a determination of nationwide scope or effect.

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit K

Petition For Reconsideration and for Stay of the Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards (Aug. 4, 2023)

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August 4, 2023

VIA E-MAIL AND FEDERAL EXPRESS

Michael Regan (Regan.Michael@epa.gov)
EPA Administrator
Office of the Administrator (1101A)
United States Environmental Protection Agency
William Jefferson Clinton Federal Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, EPA–HQ–OAR–2021–0668, 88 Fed. Reg. 36,654 (June 5, 2023)

Dear Administrator Regan:

On behalf of my client, United States Steel Corporation, please find enclosed a petition for reconsideration and stay of the Environmental Protection Agency's final rule Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0668; 88 Fed. Reg. 36,654 (June 5, 2023).

Please contact me with any questions you may have.

Sincerely,

John D. Lazzaretti

Enclosure

cc: Elizabeth Selbst (selbst.elizabeth@epa.gov)
Gautam Srinivasan (Srinivasan.Gautam@epa.gov)

BEFORE THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

In re: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)	EPA Docket Nos. EPA–HQ–OAR–2021–0668 FRL–8670–02–OAR

PETITION FOR RECONSIDERATION AND FOR STAY OF THE FEDERAL "GOOD NEIGHBOR PLAN" FOR THE 2015 OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS

SUBMITTED BY

UNITED STATES STEEL CORPORATION

Pursuant to § 307 of the Clean Air Act (42 U.S.C. § 7607) and § 705 of the Administrative Procedure Act ("APA") (5 U.S.C. § 705), United States Steel Corporation ("U. S. Steel") submits this Petition for Reconsideration and Stay ("Petition") requesting that the United States Environmental Protection Agency ("EPA") reconsider and revise its Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023) ("Good Neighbor Plan" or "Final Rule").

Under the Clean Air Act, reconsideration is required to address both circumstances that arise after the close of the public comment period but before the time for judicial review, and to allow for notice and comment on elements of the final rulemaking that were not a logical outgrowth of the proposed rule. Both of these elements apply to the Good Neighbor Plan.

The factual circumstances on which the Good Neighbor Plan relied have changed dramatically since the close of the public comment period. Most significantly, courts have stayed EPA's disapproval of SIPs for ten States, denying EPA of the legal authority to promulgate the FIP for almost half of the States EPA assumed would be subject to the rule when it was proposed.

The Final Rule also contains several departures from the Proposed Rule[1] that cannot be considered logical outgrowths of the rulemaking process. These include EPA's reliance on new modelling that was not available to the public until, in some cases, the day the Administrator signed the Final Rule. For iron and steel mills, it also includes a complete rewrite of the regulatory requirements, including the introduction of a new test-and-set process for reheat furnaces that is legally impermissible and unreasonable. For boilers, the Final Rule's applicability to boilers at iron and steel mills significantly departed from the proposed rule (from 100 tons per year potential to emit to 100 MMBTU design capacity—regardless of the unit's potential to emit (with a low use exception). By EPA's own admission, the Final Rule is

[1] Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Primary Ozone National Ambient Air Quality Standard, 87 Fed. Reg. 20,036 (April 6, 2022) ("Proposed Rule").

capturing additional boilers that would not have been subject to the Proposed Rule. Final Rule at 36,819. The regulated community had no opportunity to evaluate the rule's impacts on these newly affected boilers until after the Final Rule was signed. The Final Rule also imposes requirements based on assumptions about timing that are unreasonable and subject only to an extension request process worded in such a way that it will be difficult to apply in many of the cases in which it will be needed.

Overall, the Final Rule shows repeated signs of haste making waste. Even without the stay of so many SIP disapprovals, EPA had two years from the date of SIP disapproval to develop a thoughtful and comprehensive FIP, yet EPA, without giving States an opportunity to cure any alleged SIP defects, took only two months before it signed the Good Neighbor Plan. This was not sufficient, as shown by repeated gaps and ambiguities in the regulatory language. The rule makes almost no mention, for example of how new units and units subject to the Final Rule after August 4, 2023 are to be incorporated. It inconsistently addresses co-fired emission units, exempting boilers, but not reheat furnaces, combusting the same types of fuel, and emission unit averaging, allowing it for engines in pipeline transportation but not reheat furnaces or boilers at iron and steel mills. The record is devoid of any rationale or explanation on these significant differences. Furthermore, it omits regulatory language on key elements such as deadlines for compliance for new units and units that exceed co-firing thresholds, and emission limits for emission units that burn process gases like blast furnace gas and coke oven gas. An administrative stay is necessary until EPA either corrects the numerous errors and gaps that are currently in the hastily drafted rule or rewrites the rule.

Because circumstances have materially changed since the close of the comment period and the Final Rule includes numerous substantive changes that were not subject to public notice and comment, reconsideration of the Good Neighbor Plan is required. Given the lack of record support for the Final Rule, and the serious legal questions raised by EPA's regulation of the iron and steel industry in particular, EPA should on reconsideration withdraw the Final Rule entirely, or at a minimum as to reheat furnaces and boilers at iron and steel mills.

U. S. Steel also requests that EPA stay the Good Neighbor Plan pending reconsideration and pending judicial review. The Good Neighbor Plan has been a highly contentious rulemaking that EPA is now without statutory authority to promulgate in ten States to which it nominally applies. Even in States for which EPA can still legally impose the Good Neighbor Plan, the legal and practical infirmness of the Good Neighbor Plan strongly supports either its total withdrawal or at least significant modification. But under the current deadlines, regulatory parties such as U. S. Steel have already needed to incur compliance costs and will need to continue to incur substantial costs in order to prepare to comply with regulations that likely will never be imposed in their current form. This waste of resources is unnecessary and serves no environmental benefit. A stay is therefore well-supported to allow EPA time to fully evaluate this petition for reconsideration and for judicial review of EPA's Good Neighbor Plan and associated SIP disapprovals to run their course.

Background

The Clean Air Act sets out a "basic division of labor" between EPA and the states in implementing national ambient air quality standards ("NAAQS"). *North Dakota v. EPA*, 730

F.3d 750, 757 (8th Cir. 2013). While EPA is responsible for setting and revising the NAAQS, "States have primary responsibility for attaining those standards within their borders." *Id.* (quotations omitted). In particular, when EPA revises a NAAQS, the Clean Air Act instructs each States to prepare a state implementation plan ("SIP") containing its plan for meeting the revised standard. 42 U.S.C. § 7410(a)(1). If a State submits a complete plan that meets the requirements of the Clean Air Act, EPA must approve it. *Id.* at § 7410(k)(3) ("the Administrator *shall* approve such submittal as a whole if it meets all of the applicable requirements of this chapter") (emphasis added). Only if a States fails to submit a complete SIP or submits a SIP that does not meet the requirements of the Clean Air Act, is EPA authorized to promulgate a federal implementation plan ("FIP") instead. *Id.* at §7410(c)(1). EPA has two years after finding a SIP submission incomplete or inadequate to promulgate the FIP. *Id.* During that time, the State can correct the deficiency. *Id.*

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 parts per billion ("ppb"). States were thus obligated to submit SIP revisions to EPA by October 1, 2018 that satisfied the requirements of the Clean Air Act. *See* 42 U.S.C. §7410(a)(1). These requirements included the "Good Neighbor" requirement, that State plans:

> (D) Contain adequate provisions—
>
> > (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—
> >
> > > (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard….

42 U.S.C. §7410(a)(2)(D).

Many states submitted SIPs in 2018 that satisfied this requirement. EPA was required to review these SIPs and approve them within a time period fixed by the Clean Air Act. *See* 42 U.S.C. § 7410(k)(2). Instead, EPA missed its deadline by several years and then, in 2022, proposed to disapprove the SIPs for 19 states based on modeling that EPA had performed in the meantime (the "2016v2" modeling).[2]

Merely proposing a SIP disapproval does not give EPA authority to promulgate a FIP. *See* 42 U.S.C. § 7410(c)(1). Despite this, EPA proceeded to propose its FIP for the Good Neighbor requirement for these 19 states plus several others less than two months after publishing the proposed SIP disapprovals. Proposed Rule at 20,036. EPA used the same 2016v2 modeling as the basis for its Proposed Rule. *Id.* at 20,082. Relying on this modeling, EPA proposed to include not just electric generating units ("EGUs"), as EPA had done in prior Good

[2] *See, e.g.*, Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9,838, 9,868 (February 22, 2022).

Neighbor FIPs, but several non-EGU source categories, including iron and steel mills. *Id.* at 20,039.

The Proposed Rule did not contain an adequate technical assessment of the iron and steel industry. As a result, it proposed requirements that were not technically feasible and inappropriate to meet the Good Neighbor requirement of the Clean Air Act. Notably, for reheat furnaces, EPA proposed an emission limit of 0.05 lb/mmBtu based on the unsupported assumption that NOx could be reduced 40% from recent Reasonably Available Control Technology ("RACT") limits through implementation of selective catalytic reduction ("SCR"). *See id.* at 20,145, Table VII.C–3. For boilers at iron and steel mills, EPA proposed an emission limit of 0.20 lb/mmBtu when burning coal, blast furnace gas, or coke oven gas, again without record support. *Id*. at 20,182, Table 1 to Paragraph (c). U. S. Steel and many others submitted detailed comments in response to the Proposed Rule, many of which were not addressed in the Final Rule or EPA's response to comments. U. S. Steel references and incorporates its prior comments. U. S. Steel Comments, EPA-HQ-OAR-2021-0668-0244 and -0798.

EPA published its final SIP disapprovals for 19 States on February 13, 2023,[3] and the Administrator signed the Final Rule only one month later, though it took several more months for the rule to be published in the Federal Register.

The Final Rule contained improvements over the Proposed Rule. U. S. Steel appreciates that significant effort was put into these revisions. But the Final Rule also materially departed from the Proposed Rule in key respects. First, EPA no longer relied on its 2016v2 modeling. Instead, it had developed a different "2016v3" modeling platform and chose to rely on this modeling instead. *See* Final Rule at 36,678. Much of the 2016v3 modeling was not made publicly available until EPA published the final SIP Disapproval in early 2023. Even then, EPA did not make its full modeling results available, choosing instead to withhold the results for model year 2026. *See* SIP Disapproval at 9,344, n. 49 (stating EPA was not providing 2026 results). Second, the emission limitations for reheat furnaces were completely rewritten. Rather than impose a specific NOx limit as proposed, the Final Rule imposes a "'test-and-set' requirement for reheat furnaces that will require the installation of low-NOx burners or equivalent technology" with a work plan requirement to design to a 40% reduction from a baseline to be established by future testing. Final Rule at 36,818. Reheat furnaces that do not obtain an approved work plan are prohibited from operating. *Id.* at 36,880; 40 CFR 52.43(d)(4)(v). Third, for boilers at iron and steel mills, recognizing the material differences in fuels combusted, the Final Rule appropriately imposes no numeric emission limit for combustion of blast furnace gas or coke oven gas. It does, however, limit the applicability of the FIP to a boiler that "receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels in the previous ozone season" and provides a method for establishing emission limitations only when combusting these fuels. *Id.* at 36,884; 40 CFR 52.45(c).

Several parties petitioned for judicial review of EPA's SIP Disapproval and moved for a judicial stay of EPA's disapprovals of certain SIPs. Those courts that have ruled on the merits of

[3] Air Plan Disapprovals: Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Re. 9,336 (Feb. 13, 2023) ("SIP Disapproval").

these motions have uniformly granted a stay. As a result, the Courts of Appeals have now stayed the FIP as to ten States.[4] These stays prevent the FIP from taking effect in over one third of the States originally subject to the Good Neighbor Plan. Additional motions to stay are still pending and may result in the Good Neighbor Plan not taking effect in additional States. EPA has issued an Interim Final Rule already staying the Good Neighbor Plan as to several States.[5] The Interim Final Rule does not address every State in which the Final Rule cannot be applied, however. It also addresses only the effective date of the Final Rule; it does not address how EPA will confront the numerous other deadlines and requirements in the Good Neighbor Plan that will not be reconcilable with a delayed effective date for the Final Rule.

Standard for Reconsideration

Under the Clean Air Act, reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection [during the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule." 42 U.S.C. § 7607(d)(7)(b). Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020).

Further, under the APA, EPA has "broad discretion to reconsider" its regulatory actions "at any time." *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017); *see also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382

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[4] Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1 (May 1, 2023) (staying Texas and Louisiana SIP disapprovals); *Arkansas v. EPA*, Case No. 23-1320, ECF 5280996 (May 25, 2023) (staying Arkansas SIP disapproval); Order, *Missouri v. EPA*, Case No. 23-1719, ECF 5281126 (May 26, 2023) (staying Missouri SIP disapproval); Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 359-2 (June 8, 2023) (staying Mississippi SIP disapproval); *Nevada Cement Co. v. EPA*, Case No. 23-682, ECF 27.1 (July 3, 2023) (staying Nevada SIP disapproval); Order, *ALLETE, Inc. v. EPA*, Case No. 23-1776 (8th Cir. July 5, 2023); Order, *Kentucky v. EPA*, Case No. 23-3216, ECF 39-2 (July 25, 2023) (staying Kentucky SIP disapproval); Order, *Utah v. EPA*, Case No. 23-9509, ECF 010110895101 (July 27, 2023) (staying Oklahoma and Utah SIP disapprovals).

[5] Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards; Response to Judicial Stays of SIP Disapproval Action for Certain States, 88 Fed. Reg. 49,295 (July 31, 2023) ("Interim Final Rule").

U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.").

Moreover, under both the Clean Air Act and APA, EPA has an obligation to "examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (quotation omitted); *see also* Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1, at 18 (May 1, 2023) (EPA must ensure it acts within a zone of reasonableness and, in particular, has reasonably considered the relevant issues and reasonably explained its decision" and a court must "set aside any action premised on reasoning that fails to account for relevant factors or evinces a clear error of judgment.") (quotations omitted). Action that is not reasonably grounded in the record or that is taken without consideration of important aspects of the problem is arbitrary and capricious. *Id.*; 42 U.S.C. § 7607(d); 5 U.S.C. § 706.

<u>Grounds for Reconsideration</u>

Given the significant changes that have occurred since the end of the public comment period for the FIP and the numerous substantial changes from the Proposed Rule, there are several independent grounds why reconsideration is required in this case.

I. Changed Circumstances Undermine EPA's Factual Foundation for the Final Rule.

When EPA published the Final Rule, it addressed 23 States, including non-EGU industrial sources in 20 States. Final Rule at 36,654. EPA repeatedly emphasized the importance of this broad geographic reach and the need for uniform application of the Good Neighbor Plan to apply across all listed States. *See, e.g.*, Final Rule at 36,673 ("Effective policy solutions to the problem of interstate ozone transport dating back to the NOx SIP Call (63 FR 57356 (October 27, 1998)) have necessitated the application of a uniform framework of policy judgments…."); *id.* at 36,691 ("In the context of addressing regional- scale ozone transport in this rule, the importance of a uniform level of stringency that extends to and includes the [Clean Air Act] section 301(d) FIP areas geographically located within the boundaries of the linked upwind states carries significant force."); *id.* at 36,746 ("*id.* at 36,828 ("the logic of our 4-step interstate transport framework…is designed to bring all covered sources within the region of linked upwind states up to a uniform level of NOx emissions performance during the ozone season"); *id.* at 36,713 ("Considering the core statutory objective of ensuring elimination of all significant contribution to nonattainment or interference of the NAAQS in downwind states and the broad, regional nature of the collective contribution problem with respect to ozone, EPA could not identify a compelling policy imperative to move to a 1 ppb threshold."); *id.* at 36,716 ("the purpose of the Step 2 threshold within the EPA's interstate transport framework for ozone is to broadly sweep in all states contributing to identified receptors above a de minimis level in recognition of the collective-contribution problem associated with regional-scale ozone transport.").

As EPA emphasized:

> the purpose of this rule is to address the interstate transport of ozone on a national scale, and the technical record establishes that the nonattainment and maintenance receptors located throughout the country are impacted by sources of ozone pollution on a broad geographic scale. The upwind regions associated with each receptor typically span at least two, and often far more, states. Within the broad upwind region covered by this rule, the EPA is applying—consistent with the methodology of allocating upwind responsibility in prior transport rules going back to the NO SIP Call—a uniform level of control stringency (as determined separately for linkages existing in 2023, and linkages persisting in 2026). (See section V of this document for a discussion of EPA's determination of control stringency for this rule.) Within this approach, consistency in rule requirements across all jurisdictions is vital in ensuring the remedy for ozone transport is, in the words of the Supreme Court, ''efficient and equitable,'' 572 U.S. 489, 519. In particular, as the Supreme Court found in *EME Homer City Generation*, allocating responsibility through uniform levels of control across the entire upwind geography is ''equitable'' because, by imposing uniform cost thresholds on regulated States, the EPA's rule subjects to stricter regulation those States that have done relatively less in the past to control their pollution. Upwind States that have not yet implemented pollution controls of the same stringency as their neighbors will be stopped from free riding on their neighbors' efforts to reduce pollution. They will have to reduce their emissions by installing devices of the kind in which neighboring States have already invested. *Id.*

Id. at 36,691.

All of these points were made under the assumption that the Final Rule would address EGU emissions from 23 States and non-EGU emissions from 20 States. As of the filing of this Petition, however, SIP disapprovals for ten of those States have been stayed, including: Arkansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nevada, Oklahoma, Texas, and Utah. Additional motions to stay are pending.[6] These SIP disapprovals are a legal prerequisite for EPA to promulgate the Good Neighbor Plan for those States. 42 U.S.C. § 7410(c)(1). Moreover, because a stay is predicated on the Courts of Appeals finding a likelihood that the petitions in those cases will succeed on the merits, there is a substantial likelihood that the FIP will never apply to most or all of these States. *See Nken*, 556 U.S. at 434. As a result, it is possible that over half the States that EPA asserted are necessary to ensure uniform efforts to reduce interstate transport of ozone, avoid generation and production shifting to less regulated states, and to ensure electric generation reliability, will not be in the Final Rule. Because their presence in the Good Neighbor Plan was a central premise of EPA's promulgation of the Final Rule, this changed circumstance alone requires reconsideration and justifies an administrative stay and a complete withdrawal or rewrite of the Final Rule.[7] Sources in the minority of States

[6] *See Ohio v. EPA*, Case No. 23-1183 (D.C. Cir); *West Virginia v. EPA*, Case No. 23-1418 (4th Cir.); *Alabama v. EPA*, Case No. 23-11196 (11th Cir.).

[7] EPA has already taken action already to stay the FIP for several of these States. Interim Final Rule at 49,295. This is not sufficient, however. Not only does it address only some of the States to which the Final Rule cannot apply, a stay of the effective date of the Good Neighbor Plan does not address EPA's lack of statutory authority to promulgate the Plan in the first place. The Clean

remaining in the FIP will be irreparably harmed and suffer significant, inequitable costs with no appreciable benefit to the air quality in downwind States. The foundation of the FIP is fatally flawed and does not serve the purpose for which it was intended.

The SIP Disapproval stays also undermine EPA's factual support for the Good Neighbor Plan. The States for which the Good Neighbor Plan is currently stayed represent a large portion of the operations that EPA assumed would be subject to its FIP as it determined what industries to regulate, what costs to consider "significant," and what emission reductions to impose. Final Rule at 36,676 ("EPA here, as it has in prior transport rulemakings for regional pollutants like ozone, identifies a uniform level of emissions reduction that the covered sources in the linked upwind states can achieve that cost-effectively delivers improvement in air quality at downwind receptors on a regional scale."); *id.* at 36,677 ("We find it reasonable in this action to again determine the amount of ''significant contribution'' at Step 3 by reference to uniform levels of cost-effective emissions controls that can be applied across the upwind sources."); *id.* at 36,683 (EPA's analysis of non-EGU emission reduction requirements "relies on evaluation of uniform levels of control stringency across all upwind states to find a level of emissions control that is cost- effective and collectively delivers meaningful downwind air quality improvement"); *id*. at 36,685 ("In this rulemaking's Step 3 analysis, the EPA is measuring emissions reduction potential from improving effective emissions rates across groups of EGUs adopting applicable pollution control measures and selecting a uniform control level whose effective emissions rates deliver an acceptable outcome under the multifactor test (including a finding of no overcontrol at the selected control stringency level)."); *id.* at 36,746 ("The EPA's criteria [for screening non-EGU industries] were intended to identify industries and emissions unit types that on a broad scale impact multiple receptors to varying degrees."). In addition, for EGUs, the number of States in the FIP has a direct correlation to the size of the trading program EPA relies on in the FIP, both to maintain a reasonable regulatory cost and to ensure adequate grid reliability. *See id.* at 36,766, n.295 (the "trading program…depend[s] on the existence of a marketplace for purchasing and selling allowances"); *id.* at 36,789 (noting the importance of "allowance market liquidity" especially during the 2024-2029 period); *id.* at 36,774 (citing "the use of a trading program as the mechanism for achieving…emissions reductions" as a factor in finding no "material risk of adverse impact to electric system reliability" and as the reason why additional accommodation for "reliability-related need" was unnecessary). EPA's policy case modeling also depended on emission reductions from these States. *See generally*, Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards, at 3 (March 2023). As a result, EPA can no longer rely on factual record and modeling EPA used to develop the Good Neighbor Plan.

The legal and factual basis for the Good Neighbor Plan has so fundamentally changed that the Final Rule can no longer stand on the current administrative record. Because these grounds arose after the public comment period but before the time for judicial review, EPA must

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Air Act speaks plainly to EPA's authority to promulgate a FIP, and it does not authorize EPA to promulgate a FIP at any time before disapproval of a State's SIP submission. 42 U.S.C. § 7410(c)(1). Even if the stay is only temporary, the deadlines in the FIP will not make sense or be reconcilable with the FIP taking effect after August 4, 2023. As a result, the FIP will have to be materially altered through further rulemaking in any event. So, there is no reason for EPA to hold on to what is ultimately an *ultra vires* act.

stay the effectiveness of the FIP and reconsider the FIP. The FIP reconsideration is necessary to determine whether, in light of the stay of EPA's SIP Disapproval for many States, and likely vacatur of EPA's SIP Disapproval, the FIP cannot still be equitably applied to the remaining States. Indeed, given the significant shift in the fundamental facts on which EPA attempted to equitably allocate regulatory burdens since the publication of the FIP, it is likely that reconsideration of the FIP will demonstrate that it must be withdrawn and redone entirely based on new modeling that incorporates the SIPs EPA will likely be unable to disapprove after the pending cases are complete.

II. The Final Rule was Not Promulgated in Accordance with Law and Arbitrarily and Capriciously Relied on Information Added After Public Comment.

EPA was required to include with its Proposed Rule a "statement of basis and purpose" including a summary of:

> (A) the factual data on which the proposed rule is based;
>
> (B) the methodology used in obtaining the data and in analyzing the data; and
>
> (C) the major legal interpretations and policy considerations underlying the proposed rule.

42 U.S.C. § 7607(d)(3). This information is necessary to allow for the "reasonable period for public participation" required by the Clean Air Act. *Id.* at § 760(h). When EPA relies on information that is not made part of the public record in time for meaningful public comment, EPA violates both the spirit and the terms of the Clean Air Act. *Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981) (if "documents of central importance upon which EPA intended to rely ha[ve] been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 [are] violated").

Several aspects of the Final Rule rely on information that EPA did not include in the public record in time for meaningful public comment. Those specific to iron and steel mills are addressed separately below. The most generally applicable addition, however, is EPA's 2016v3 modeling, which was used to support EPA's Step 1 and Step 2 analysis for all affected States. The Proposed Rule was based on modelling that EPA refers to as its "2016v2" modeling. *See* Final Rule at 36,673. But EPA did not rely on the 2016v2 results for the Final Rule. Instead, EPA "revised its 2016v2 modeling platform and input since the platform was made available for comment" to create the 2016v3 modeling. *Id*. at 36,674. It then "reassessed" its modeling results "to inform the final action." *Id*. These were not minor amendments. EPA "evaluated a raft of technical information and critiques of its 2016v2 modeling" and "incorporated updates into the version of the modeling used to support this final rule (2016v3)." *Id*. Further, while EPA released some of its 2016v3 results with the SIP Disapproval in February 2023, it withheld the results for model year 2026, asserting that these results were "not applicable and were not used in this final action." SIP Disapproval at 9,344, n.30. As a result, EPA did not release the full modeling results on which the Final Rule is based until the Administrator signed it in March 2023.

This delay in releasing the modeling that was central to EPA's Final Rule was "highly improper." *Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 508, 540 (D.C. Cir. 1983); *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) ("the safety valves in the use of such sophisticated methodology [as computer modeling] are the requirement of public exposure of the assumptions and data incorporated into the analysis and the acceptance and consideration of public comment.") (alterations and quotations in original omitted). EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id*. at 540.

This was also not the first time EPA switched the information on which it relied after a relevant deadline. The 2016v2 modeling that EPA relied on for the Proposed Rule was itself not introduced until EPA published its proposed SIP disapprovals for 19 States, despite the SIPs having been submitted to EPA years before based on modeling EPA released in 2018. *See, e.g.* 87 Fed. Reg. at 9,840. When EPA switched to reliance on the 2016v2 platform, it gave the public an unreasonably short time to comment, allowing only two months. *See id.* at 9,838. For the Proposed Rule, EPA offered only slightly more time, giving the public less than three months to request, process, verify, and analyze EPA's modeling results, despite numerous requests for more time, including from U. S. Steel. *See* USS FIP Comments at 42. As EPA knows, these models are large data files. They are not made part of the online docket and must be specially requested from EPA. The process takes several weeks to obtain the data and in this case several requests to obtain a full data set. Several more weeks are needed to load and verify it before EPA's modeling can be checked for errors and public comments prepared. Overall, this process typically takes two to three months, and can take longer. Two or even three months after announcing the availability of its 2016v3 modeling was simply insufficient time to allow for meaningful public participation as envisioned by the Clean Air Act. *See* 42 U.S.C. § 7607(h).

When EPA changed the game and switched models again for the final SIP Disapproval and FIP, EPA again gave no prior access to its results. EPA also did not make the complete modeling files immediately available. As raised in a separate petition for reconsideration and stay of EPA's disapproval of Minnesota's SIP (attached as Attachment B), EPA's initial release of 2016v3 modeling data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the necessary data, as well as checking its accuracy, took several more weeks. In the case of the 2016v3 modeling, U. S. Steel's contractor, Trinity, also needed to contact Ramboll Environ (the CAMx developer) directly to address problems with EPA's source apportionment modeling before it could be checked. This deprived U. S. Steel and the public generally of the opportunity to comment on EPA's modeling. *See Kennecott* 684 F.2d at 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations); *Riverkeeper, Inc. v. EPA*, 475 F.3d 83, 112-113 (2d Cir. 2007) (finding EPA's Notice of Data Availability insufficient when it omitted information that would have afforded the public the opportunity to make facility-specific comments).

This procedural impropriety was centrally relevant to the outcome of the Final Rule. The 2016v3 modeling forms the basis for "EPA's understanding of projected air quality conditions and contributions" in the Final Rule, which in turn underlie EPA's selection of receptors and State contribution levels. Final Rule at 36,673. Even in the limited time the public has had with the modeling files, significant problems have been identified with EPA's 2016v3 modeling. *See* Petition for Reconsideration and Stay of the SIP Disapproval at 8-14. Correcting for these issues would likely result in at least Minnesota being excluded from the Final Rule.[8]

EPA's modeling for 2026 (which was not released until well after the close of public comment on the Final Rule) is equally important, since it informed both the application of additional emission reductions for EGUs and the introduction of emission requirements for non-EGU industrial sources. *See* Final Rule at 36,654. Indeed, in light of this modeling, EPA found that three States (Alabama, Minnesota, and Wisconsin) would be limited to emission reductions achievable by the 2024 ozone season. Final Rule at 36,660. Other States, including Arkansas and Illinois, had their compliance status change, from being modeled to interfere with attainment in 2023 to being modeled only to interference for maintenance in 2026 modeling. *See id.* at 36,710, Table IV.F–2. This information, had it been available during public comment, would have allowed commenters, including U. S. Steel to address the downward trends in significant contribution EPA has modeled for 2026 and which EPA has itself recognized are significant to identifying maintenance-only receptors. *See* EPA, Considerations for Identifying Maintenance Receptors (Oct. 19, 2018).

EPA's late publication of modeling which is central to its Final Rule violated the procedural requirements of the Clean Air Act and the APA; and justifies reconsideration to allow for full notice and public comment on the modeling supporting the Final Rule.

III. EPA Rushed Promulgation the Good Neighbor Plan in Violation of Cooperative Federalism.

EPA had two years from its SIP Disapproval to promulgate a FIP for most states. 42 U.S.C. § 7410(c)(1). EPA has asserted that it does not need to "postpone its action even a single day" after disapproving a SIP. FIP at 36,689 (*quoting EPA v. EME Homer City Generation, L.P.*, 572 U.S. 489, 509 (2014)). But the Supreme Court was speaking to whether the Clean Air Act required delay absent other considerations. The Supreme Court did not hold that EPA can steamroll State SIP authority simply because Congress did not include a minimum waiting period before EPA can promulgate a FIP. To the contrary, the Supreme Court has repeatedly held that agencies must interpret their statutory obligations "with a view to their place in the overall statutory scheme," and cannot act in a manner that is "'incompatible' with 'the substance of Congress' regulatory scheme.'" *UARG v. EPA*, 573 U.S. 302, 322 (2014) (*quoting FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 133 and 156 (2000)). When, for example, States do not submit SIPs at all, there may be no reason to wait a single day after EPA's finding of incompleteness to promulgate a FIP. Here, 19 states submitted SIPs, appropriately relying on EPA policy and guidance and air modeling that was supported by EPA and available at the time, in a good faith attempt to maintain their primary role as regulators of the Good Neighbor requirement for the 2015 ozone NAAQS. Rather than give these SIPs a full and fair evaluation,

[8] Since the submission of that petition, additional discrepancies in EPA's air quality modeling have been identified, as are being raised in the separate Petition for Reconsideration and Stay of the FIP being submitted by the Minnesota Good Neighbor Coalition contemporaneously with these comments and only further underscore that, correcting the flawed 2016v3 modeling will likely result in significant changes to the conclusions EPA reached in the Final Rule.

EPA issued late and incomplete modeling, changed its position on published guidance many States used to support their SIPs, gave only limited opportunity for public comment, and rushed out a SIP Disapproval, all with the apparent purpose of paving the way for a FIP that was equally rushed and equally short on public input. Under these circumstances, EPA's decision to simultaneously prepare a SIP Disapproval and FIP violated the Cooperative Federalism at the foundation of the Clean Air Act and was "incompatible with the substance of Congress' regulatory scheme." *UARG*, 573 U.S. at 320 (quotations omitted).

EPA was required to take sufficient time in developing its FIP to ensure that States' primary role in the NAAQS process could be fulfilled. The multiple stays of EPA's SIP Disapproval that have been issued attest to the fact that EPA did not do so here.

EPA should use its reconsideration authority as an opportunity to correct its rush to judgment, and in this instance in particular, considering the scope and complexity of the issues, use the Congressionally-provided two year period for promulgation of FIPs to both work with States on the development of compliant SIPs and, only if necessary, promulgate a FIP.

IV. The Deadlines in the Final Rule Are Incompatible with the Regulation of New Affected Units and Existing Affected Units that Become Subject to the FIP After the Effective Date.

The Good Neighbor Plan applies to two types of emission units: "existing affected units," units constructed on or before August 4, 2023; and "new affected units," units constructed after this date. *See* 40 CFR 52.40(b). Existing affected units are also not all subject to the FIP as of the Effective Date (August 4, 2023). For example, the FIP includes exemptions for low-use boilers and boilers that combust less than 90% natural gas, residual oil, distillate oil, and coal. Final Rule at 36,884; 40 CFR 52.45(b). As a result, even an existing affected unit can become subject to the FIP years after August 4, 2023.[9] The Final Rule, however, makes no provision for these units. With only limited exceptions, compliance dates, submission deadlines, and reporting requirements are recorded as fixed dates in the Final Rule, rather than running from the date of applicability. The result is an ambiguous set of irreconcilable deadlines for units that are not subject to the FIP as of August 4, 2023.

Overall, EPA should reconsider and revise the FIP to comprehensively address these issues, but U. S. Steel identifies several particular examples where post-Effective Date applicability creates particular problems.

A. The Final Rule Does Not Give Sufficient Time for Co-Fired Boilers and Reheat Furnaces.

While the Proposed Rule included emission limits for co-fired boilers, the Final Rule applies only to boilers that combust 90% or more natural gas, distillate oil, residual oil, or coal in the previous ozone season. Final Rule at 36,884; 40 CFR 52.45(b). As discussed in Ground for Reconsideration VIII below, the same exemption should be included for reheat furnaces as well.

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[9] Similarly, for existing affected units in states subject to a stay of the FIP, if they will become subject to the FIP at all, it will be at a date after August 4, 2023.

In either case, therefore, there is a possibility that a co-fired unit will lose the exemption if it stops burning process gas at some point in the future for an ozone season. Yet the Final Rule offers no language directly addressing when such units must meet the requirements of the Good Neighbor Plan.

To the extent this would mean that a boiler, for example, will need to be prepared to comply with the Good Neighbor Plan by the start of the next ozone season, this would entail potentially installing CEMS, obtaining permits, designing and installing pollution control equipment, and implementing recordkeeping and reporting requirements within a matter of months, not the nearly four years allowed for boilers subject to the Final Rule as of the Effective Date. For reheat furnaces, it would entail preparing a work plan and having it approved by EPA within a similarly short time period.

The time EPA has allowed for boilers to comply with the Final Rule was meant accommodate the real-world practical requirements of designing, installing and testing new pollution control equipment. *See* NOx Control Installation Timing Report ("Timing Report"). Interim deadlines were fixed to allow each step. As discussed in Ground for Reconsideration XII below, the schedule for boilers does not sufficiently accommodate these requirements and should be extended, but it is arbitrary and capricious to subject units that were exempt from compliance to an even shorter deadline. Indeed, EPA recognized in the Proposed Rule that a "3-year period for installation of post-combustion control technologies is consistent with the statutory timeframe for implementation of the controls required to address interstate pollution under section n110(A)(2)(D) and 126 of the [Clean Air] Act, the statutory timeframes for implementation of RACT in ozone nonattainment areas classified as Moderate or above, and other statutory provisions that establish control requirements for existing stationary sources of pollution." Proposed Rule at 20,101. There is no justification in the record for why a substantially shorter time should apply to emission units that lose an applicable exemption.[10]

EPA must address the lack of deadlines for post-Effective Date boilers and reheat furnaces on reconsideration. In doing so, EPA should allow the same time to achieve compliance as current units subject to the FIP effective August 4, 2023.

B. Compliance Dates for States in which the Good Neighbor Plan has been Stayed Must be Extended.

As discussed above, the Good Neighbor Plan has been stayed, either by court order or Interim Final Rule, in ten states already, with the possibility that additional stays will be issued. In these states, the Good Neighbor Plan will not take effect August 4, 2023. Neither the Final Rule nor the Interim Final Rule, however, makes accommodation for extending the deadlines in the Good Neighbor Plan for emission units subject to a stay.

As one example, owners and operators of reheat furnaces are to submit work plans by August 4, 2024. Final Rule at 36,879; 40 CFR 52.43(d). To do this will reasonably require a

[10] Even for the low-use exemption, which EPA has asserted must result in compliance in one year, there is nothing in the record to support this short of a compliance deadline. Final Rule at 36,884; 40 CFR 52.45(b)(2)(i).

year of work, as EPA anticipated when it set the deadline one year after the Effective Date. Yet owners and operators in a State subject to a stay cannot reasonably be expected to develop work plans until the stay is lifted. This may not occur before August 4, 2024 and, if it does, it will still not leave sufficient time to develop the required content. As a result, to fulfill the requirements of the stay orders currently in place, and to preserve the *status quo* prior to promulgation of the SIP Disapproval, EPA must extend this and other deadlines in the Final Rule to allow reasonable time to comply after the stays are lifted.

C. The Final Rule's Procedures for Requests for Extension and Case-By-Case Emission Limits Do Not Address Post-Effective Date Applicability.

EPA requested comment in the Proposed Rule on "whether the FIP should provide a limited amount of time beyond the 2026 ozone season for individual non-EGU sources to meet the emissions limitations and associated compliance requirements, based on a facility-specific demonstration of necessity." Final Rule at 20,104. EPA did not propose a process for case-by-case emission limits.

In the Final Rule, EPA promulgated procedures for both requesting an extension of compliance (40 CFR 52.40(d)) and requesting a case-by-case emission limit (40 CFR 52.40(e)). Final Rule at 36,870-71. Neither of these procedures was provided in the Proposed Rule, so it would have been impracticable to raise objections to EPA's procedure during public comment. 42 U.S.C. § 7607(d)(7)(B).

While U. S. Steel supports providing flexibility to owners and operators, both in terms of the compliance schedule and the emission limits in the Final Rule, the procedures EPA has adopted leave significant issues unaddressed. The Final Rule language does not mention new affected units at all, and by including specific dates for applications and dates to which compliance can be extended, the Final Rule does not adequately address existing affected units that become subject to the Good Neighbor Plan after August 4, 2023.

The current language in 40 CFR 52.40(d), for example, allows the "owner or operator of an existing affected unit" to "request an initial compliance extension to a date certain no later than May 1, 2027," almost four years after the Effective Date of the Final Rule. Final Rule at 36,870; 40 CFR 52.40(d)(1). A second extension can be requested to "a proposed compliance date no later than May 1, 2029." *Id;* 40 CFR 52.40(d)(3)(v). These deadlines would be inequitable if applied to emission units that become subject to the Good Neighbor Plan after August 4, 2023, and, of course, do not make sense at all for an emission unit that becomes subject to the Good Neighbor Plan after each date.

EPA included the extension provision because it found "not all facilities may be capable of meeting the control requirements" by 2026, though EPA acknowledged that the "circumstances where an extension may be warranted for any specific facility are unknown at this time and will be evaluated through a source-specific application process, where the need for extension can be established with source-specific evidence." Final Rule at 36,664 and 36,749. There is no rational basis why similar source-specific showings of necessity should not justify a comparable extension for other units that become subject to the Good Neighbor Plan after the Effective Date.

Similarly, in the Final Rule, EPA recognized that "there may be unique circumstances the Agency cannot anticipate that would, for a particular source, render the final emissions control requirements technically impossible or impossible without extreme economic hardship." Final Rule at 36,818. To address this, EPA included "a provision that allows a source to request EPA approval of a case-by-case emissions limit based on a showing that an emissions unit cannot meet the applicable standard due to technical impossibility or extreme economic hardship." *Id.* Since technical impossibility and extreme economic hardship are not limited to existing affected units subject to the Final Rule as of the Effective Date, there is no reasonable basis for EPA to exclude units subject to the Good Neighbor Plan after the Effective Date from the same opportunity. Yet the language EPA chose for the Final Rule requires requests to be submitted "by August 5, 2024." Final Rule at 36,781; 40 CFR 52.40(e)(1).

EPA should reconsider its use of fixed dates in the Final Rule and instead adopt deadlines based on the date of applicability of the FIP to an affected unit.

V. EPA Has Not Justified Including Reheat Furnaces and Boilers at Iron and Steel Mills in the Final Rule.

The Final Rule does not regulate every source of NOx in each upwind State nor should it. Instead, EPA attempted to "focus[] on the most impactful industries and emissions units as determined by [the Agency's] evaluation of the power sector and the non-EGU screening assessment prepared for the proposal….." Final Rule at 36,682. This screening assessment determined which industries would be subject to the Good Neighbor Plan. Indeed, of the 41 industries EPA examined in this screening assessment, EPA selected only nine for inclusion in the Final Rule. *Id.* This screening assessment was also used "[t]o identify appropriate control strategies for non-EGU sources to achieve NOx emissions reductions that would result in meaningful air quality improvements in downwind areas" and to assess control costs. *Id.* at 36,661, 36733. Thus, the screening assessment formed a significant basis for EPA's inclusion of regulations for reheat furnaces and boilers at iron and steel mills in the Final Rule and EPA's selection of appropriate emission reductions for them.

This screening assessment did not identify all emissions from each industry. Rather it focused on "potentially controllable emissions," which it identified by focusing on sources that could provide "the most emissions reductions" at a marginal cost threshold. Screening Assessment at 2. "[W]ell-controlled sources" were expressly to be "excluded from consideration." *Id.* at 3. At the time of the Screening Assessment, EPA assumed, incorrectly, that emissions from co-fired boilers, blast furnaces, casting and tapping, basic oxygen furnaces, sintering, and other processes, all constituted "potentially controllable emissions." *See id.* at 17, Table 6. In the Final Rule, however, EPA appropriately recognizes that additional emission reductions from these sources are not technologically or economically feasible. *See* Final Rule at 36,827 ("the data we have reviewed is insufficient at this time to support a generalized conclusion that the application of NOx controls, including SCR or other NOx control technologies such as LNB, is currently both technically feasible and cost effective on a fleetwide basis for these emission source types in this industry"); *id.* at 36,833 ("The EPA does not have sufficient information at this time to conclude that [boilers] burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost."). As a result, the Screening Assessment overcounted emissions from iron and steel mills. This required updating before EPA relied on the Screening Assessment results in the Final Rule. It was not. Instead, the Final Rule continues to rely on the same, obsolete and incorrect, Screening Assessment. *Id.* at 36,732-33.

This results in the inconsistent treatment of iron and steel mills as compared with other industries with comparable "potentially controllable emissions," and ultimately, results in a Final Rule that is inconsistent with the record and inequitable impacts.

U. S. Steel already submitted comments on the technical and economic infeasibility of the assumptions made in the Screening Assessment. *See, e.g.*, USS FIP Comments at 13-18. EPA's decision to continue to rely on the Screening Assessment in the Final Rule, however, despite the inaccuracy of its assumptions about the availability of additional emission reductions from the iron and steel mill industry did not arise until the Final Rule and so would have been impracticable to raise in public comments on the Proposed Rule. 42 U.S.C. § 7607(d)(7)(B).

On reconsideration, EPA should revise its Screening Assessment to address only emissions from iron and steel mills associated with reheat furnaces and boilers combusting natural gas, residual oil, distillate oil, and coal. In addition, as discussed in Ground for Reconsideration VI below, the iron and steel industry is subject to many additional and pending NOx reduction requirements that will further limit the availability of additional emission reductions. Since these were not factored into EPA's initial Screening Assessment, reconsideration will present the opportunity for to EPA incorporate a more up-to-date and realistic assessment of reheat furnace and boiler impacts on downwind ozone concentrations, which will likely result in the conclusion that the iron and steel industry, like many other industries, should not be subject to the Good Neighbor Plan.

VI. The Final Rule Did Not Adequately Consider the Cumulative Burdens of Pending EPA Regulations.

The Good Neighbor Plan is only one of many regulations impacting the iron and steel industry, including the same reheat furnaces and boilers subject to the Final Rule, including:

- National Emission Standards for Hazardous Air Pollutants: Taconite Iron Ore Processing Amendments, 88 Fed. Reg. 30,917 (proposed May 15, 2023);
- National Emission Standards for Hazardous Air Pollutants: Integrated Iron and Steel Manufacturing Facilities Technology Review, 88 Fed. Reg. 49,402 (proposed July 31, 2023);
- Standards of Performance for Steel Plants: Electric Arc Furnaces Constructed After 10/21/74 & On or Before 8/17/83; Standards of Performance for Steel Plants: Electric Arc Furnaces & Argon-Oxygen Decarburization Constructed After 8/17/83, 87 Fed. Reg. 29,710 (signed Aug. 1, 2023) (https://www.epa.gov/stationary-sources-air-pollution/electric-arc-furnaces-eafs-and-argon-oxygen-decarburization);

- Proposed Amendment to Air Toxics Standards for Coke Ovens Pushing, Quenching and Battery Stacks; and Coke Oven Batteries (Residual Risk and Technology Review, and Periodic Technology Review (proposed rule signed by EPA Administrator Regan on July 31, 2023. (https://www.epa.gov/stationary-sources-air-pollution/coke-ovens-batteries-national-emissions-standards-hazardous-air);

- Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, 88 Fed. Reg. 5,558 (proposed Jan. 27, 2023); and

- EPA Announcement: EPA to Reconsider Previous Administration's Decision to Retain 2015 Ozone Standards, https://www.epa.gov/ground-level-ozone-pollution/epa-reconsider-previous-administrations-decision-retain-2015-ozone.

In developing the Good Neighbor Plan, EPA aimed to incorporate "emissions reductions from on-the-books actions, planned emissions control installations, and promulgated Federal measures that affect anthropogenic emissions" in its 2023 and 2026 emission inventories. Final Rule at 36,698. EPA did not, however, incorporate emission reductions from these and other rules that will significantly impact that NOx emissions from the iron and steel industry.

Equally problematic, while EPA has sought to reflect emission reductions from other regulations, EPA did not incorporate these other obligations into the Good Neighbor Plan's selection of emissions control strategies and calculation of compliance costs. The result is a rule that does not adequately consider the circumstances facing the regulated community. *See* Declaration of Alexis Piscitelli at ¶¶20-28 (attached hereto as Attachment A).

Siloed rulemakings present a jigsaw puzzle of requirements that U. S. Steel and others must piece together under strict compliance deadlines. At a minimum, this is inefficient and not conducive to maximizing environmental benefit. At worst, it can result in conflicting and inconsistent legal requirements. *See id.* As one clear example, EPA is rushing to impose the Good Neighbor Plan to address the 2015 ozone NAAQS while it has already announced its intention to reconsider those standards.[11] It does not make sense to expend millions of dollars in designing and implementing pollution controls to meet standards that EPA is in the process of reconsidering.

On reconsideration, EPA should incorporate consideration of all pending iron and steel industry regulations, which will further support exclusion of reheat furnaces and boilers from a final revised Good Neighbor Plan.

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[11] https://www.epa.gov/ground-level-ozone-pollution/epa-reconsider-previous-administrations-decision-retain-2015-ozone.

VII. The August 4, 2023 Deadline for Federally Enforceable Changes to Potential to Emit for Reheat Furnaces is Unreasonable.

The Final rule requires limitations on a reheat furnace's potential to emit to be effective by the Effective Date of the Good Neighbor Plan to be relevant to determining applicability. Final Rule at 36,879; 40 CFR 52.43(b) ("Any existing reheat furnace with a potential to emit of 100 tons per year or more of NOx on August 4, 2023, will continue to be subject to the requirements of this section even if that unit later becomes subject to a physical or operational limitation that lowers its potential to emit below 100 tons per year of NOx."). This aspect of determining potential to emit was not part of the Proposed Rule or a logical outgrowth of the Proposed Rule. As a result, it was impracticable to comment on it during the public comment period. 42 U.S.C. § 7607(d)(7)(B).

EPA has given no reason for adding this provision in the Final Rule in its statement of basis and purpose. This alone violates the procedural requirements of the Clean Air Act. 42 U.S.C. § 7607(d)(6). It is also improper. Long-standing EPA policy approves the use of legally-enforceable limitations on potential to emit to conform emission units to the applicability requirements of EPA's Clean Air Act regulations. *See, e.g.* EPA, Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act), EC-6-1998-29 (Jan. 25, 1995). Removing this option requires a "reasoned explanation," which is absent from the Final Rule. *U.S. Sugar Corp. v. EPA*, 830 F.3d 579, 626 (D.C. Cir. 2016); *see also FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

Limiting the time in which potential to emit can be changed is also of questionable value. A federally-enforceable limitation on potential to emit puts an existing affected emission unit in the same position whether the limitation is adopted before or after August 4, 2023. It also puts existing affected units in the same position as new affected units, which can design to a potential to emit after the Effective Date.

EPA has also not applied these requirements consistently across industries. Similar provisions are included in the Final Rule for iron and steel, cement, and glass manufacturing. *See* 40 CFR 52.42(b), 52.43(b), and 52.44(b). But the Final Rule does not impose similar time restrictions on emission units in other non-EGU industries. *See* 40 CFR 52.41(b), 52.45(b), and 52.46(b). The lack of any explanation why certain industries are barred from relying on federally-enforceable limitations after a specific date is a material omission from the Final Rule.

As a practical matter, it is also unfair to subject owners and operators to applicability requirements that require State involvement and quick turnaround. Obtaining federally-enforceable limitations on potential to emit typically requires amendment of State-issued permits. EPA's own Timing Report states that even minor permit modifications can take "a few weeks or months." Timing Report at ES-3. As discussed in Ground for Reconsideration XI below, this is overly optimistic in many cases, particularly when permitting offices are backlogged. FIP applicability should not depend on such factors.

EPA should reconsider the inclusion of this provision in 40 CFR 52.43(b) and remove it. Even if EPA were to conclude that some cut-off for applying physical and operational limitations on potential-to-emit is necessary (and EPA justifies such a cut-off in the statement of basis and purpose as required by the Clean Air Act), EPA should select a date that is both grounded in the emission reduction requirements of the Good Neighbor Plan and that does not unfairly prejudice facilities in States with significant permitting backlogs. For example, under the current Good Neighbor Plan, there is no justification for imposing such a requirement before May 1, 2026, the "compliance date that generally applies to all affected units in the non-EGU industries covered by this final rule." Final Rule at 36,818.[12]

VIII. EPA Should Exempt Co-Fired Reheat Furnaces from the Good Neighbor Plan.

The Final Rule acknowledges that "EPA does not have sufficient information at this time to conclude that [boilers] burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost." Final Rule at 36,833. EPA does not appear to have considered that similar fuels are used by reheat furnaces, let alone put information in the record to support treating reheat furnaces and boilers that combust more than 10% process gas differently. Indeed, as explained in U. S. Steel's FIP Comments, low-NOx burners were also recently eliminated as a control option for blast furnace stoves fueled primarily by blast furnace gas, and they offer limited potential for emission reduction in light of co-firing and negative energy usage impacts arising from the lower flame temperature with low-NOx burners. thermodynamics of heat transfer to the steel in a reheat furnace. USS FIP Comments at 15 and Exhibit D at § 1.2.5. EPA's finding that there is "[in]sufficient information at this time to conclude that units burning more than 10 percent fuels other than coal, residual or distillate oil, or natural gas can operate the necessary controls effectively and at a reasonable cost" applies equally to reheat furnaces. Yet the Final Rule includes no similar provision excluding reheat furnaces that burn more than 10 percent process gas from the Good Neighbor Plan. U. S. Steel fully supports the exemption of boilers that combust primarily process gas from the Good Neighbor Plan. But having introduced this exemption in the Final Rule, EPA must also apply it consistently.

The applicability provisions for reheat furnaces and boilers were substantially rewritten from the Proposed Rule, and EPA did not raise in the Proposed Rule that it was considering a heat input exemption for process gas-fired emission units. As a result, it would have been impracticable to address EPA's omission of the exemption for reheat furnaces during the public comment period. 42 U.S.C. § 7607(d)(7)(B). On reconsideration, EPA should incorporate a similar exemption for reheat furnaces.[13] Even if EPA determines that reheat furnaces that co-fire process gas should be subject to the Good Neighbor Plan (and provides an adequate explanation for including them), at a minimum, EPA should clarify the determination of potential to emit for these units. As reflected in the emission requirements for boilers, the use of different fuels results in a different NOx emission rate for comparable heat input. *See* 40 CFR 52.45(c). Similarly, in determining potential to emit for co-fired reheat furnaces, a 100 tpy threshold would

[12] The Final Rule technically omits this language from the emission limitation in 40 CFR 52.43(c). This was clearly an omission and should be corrected on reconsideration as well, to make clear that the emission limit applies "[b]eginning with the 2026 ozone season" or, as discussed in Ground for Reconsideration IV above, within three years following the date the Good Neighbor Plan becomes applicable to an emission unit.

[13] As discussed in Ground for Reconsideration IV above, deadlines should also be included in 40 CFR 52.43(c) for furnaces that lose this exemption after the Effective Date.

capture differently-sized units depending on whether potential to emit is determined based on combustion of natural gas or process gas.

IX. The Work Plan Process for Reheat Furnaces is *Ultra Vires* and Violates Due Process.

A Good Neighbor implementation plan is to contain emission limitations ("prohibit[ions]" on "emissions activity"). 42 U.S.C. § 7410(a)(2)(D)(i). The Clean Air Act sets forth specific procedural requirements EPA must follow to impose these emission limitations. 42 U.S.C. § 7607(d). This includes publication of a proposed rule in the Federal Register, provision of a statement of basis and purposes, creation of a public docket of supporting material, public comment, and response to significant comments. *Id.* at § 7410(d)(3)-(6). Public participation must be for "a reasonable period" and by "at least 30 days" unless expressly provided for otherwise in the Clean Air Act. *Id*. at § 7607(h). Final emission limitations are also subject to judicial review. *Id.* at § 410(d)(7).

The Final Rule does not impose emission limitations on reheat furnaces. Instead, it imposes a "test-and-set requirement for reheat furnaces that will require the installation of low-NOx burners or equivalent technology." Final Rule at 36,818. Specifically, it requires owners and operators to submit a work plan and "establish an emissions limit in the work plan that the affected unit must comply with." *Id.* at 36,879; 40 CFR 52.43(d)(3). U. S. Steel agrees with EPA's conclusion that "[d]ue to variations in the emissions rates that different types of reheat furnaces can achieve," EPA should not "finaliz[e] one emissions limit for all reheat furnaces." Final Rule at 36,828. And while EPA recognized that furnace-specific factors make a universal one-size-fits-all approach inappropriate for reheat furnaces, it somehow disregarded these factors when imposing a universal reduction mandate in the Final Rule. A universal reduction of 40% from baseline is not appropriate because it does not take into account what is achievable for each reheat furnace, including what the baseline value actually is—whether, for example, it is 0.12 lb/MMBtu or 0.24 lb/MMBtu, what limits there are on the type of NOx reduction technology that can be used, what fuels the reheat furnace uses, what other pollution control technologies are already in place, or other factors that would make a minimum 40% reduction on some units technically or economically infeasible. *See* Attachment A at ¶¶11-12. EPA's own analysis of low-NOx burners shows this bearing true, as it merely cites to an application of low-NOx burners at a reheat furnace that achieved a 20% reduction in NOx. *See* Proposed Rule at 20,145, Table VII.C-3. EPA has not provided any basis for the 40% reduction requirement—and such a requirement is devoid of any explanation and is therefore arbitrary and capricious.

U. S. Steel appreciates that EPA was looking to provide flexibility through the work plan process in the Final Rule, both on phased construction timeframes and the final emission limits. The logical result or outgrowth of finding that there is insufficient information in the record to support an emission limit for reheat furnaces, however, is to exclude reheat furnaces from the Good Neighbor Plan—not to establish a mandate the reduce NOx by 40% from baseline. EPA cannot put in a placeholder and then use a work plan process to develop future record support. 42 U.S.C. § 7607(d)(6)(C) ("The promulgated rule may not be based (in part or whole) on any information or data which has not been placed in the docket as of the date of such promulgation."). The procedure EPA has included in the Final Rule for establishing the final emission limits for reheat furnaces falls short of these requirements. U. S. Steel and others similarly situated had no opportunity to comment on the Work Plan requirement or the 40% reduction mandate.

The work plan process in the Final Rule also raises serious Due Process concerns. The Final Rule provides that the Administrator will determine completeness of a work plan within 60 calendar days (40 CFR 52.43(d)(4)(i)), and then, within 60 calendar days after notification of a complete work plan, notify the owner and operator via CEDRI or analogous electronic submission system whether EPA approves the work plan (40 CFR 52.43(d)(4)(iv). Final Rule at 36,879-80. The Final Rule does not say what is to be done if the Administrator approves the work plan, but if the Administrator does not approve it, the owner or operator has only 15 calendar days to present in writing additional information or arguments, after which the Administrator can issue a final decision disapproving the work plan. *Id.* at 36,880; 40 CFR 52.43(d)(4)(iii). If the Administrator disapproves a work plan or finds or work plan was not timely submitted or completed, "[e]ach day that the affected unit operates following such disapproval of failure to submit shall constitute a violation." *Id.*; 40 CFR 52.43(d)(v).

This work plan process raises several concerns. First, this effectively imposes an emission limit of zero, unless an owner or operator can demonstrate to EPA's satisfaction that a higher limit should apply. This turns the rulemaking process on its head and finds no support in the Clean Air Act.

Second, the procedural rights it affords clearly fall short of what would be required for a prohibition on operation. Even in the case of a 126 petition, through which the Clean Air Act expressly authorizes EPA to limit the emissions of a particular "major source or group of major sources" to prevent "violation of the prohibition of section 7410(a)(2)(D)(ii)," the Clean Air Act requires both a public hearing and the provision of at least three months for a source to come into compliance while continuing to operate. 42 U.S.C. § 7426(b). There is no justification for imposing an even more draconian ban—with less process—through implementation of a FIP that is expressly required to avoid over-control. *See, e.g.*, Final Rule at 36,704; *EME Homer City*, 572 U.S. at 523.

Third, EPA's work plan process circumvents the notice and comment rulemaking procedure EPA is required to follow in 42 U.S.C. § 7607(d), including publication of both the proposed and final emission limit in the Federal Register, provision of at least 30 days for public comment, a requirement that EPA will respond to all significant comments, requirement that issuance of the final decision and statement of basis will be published in the Federal Register, and that EPA's final decision will be subject to judicial review. In the regional haze test-and-set process EPA adopted for certain taconite furnaces, for example, the emission limits to be set become enforceable "only after EPA's confirmation or modification of the emission limit in accordance with" procedures that include EPA taking "final agency action by publishing its final confirmation or modification of the NOx limit in the Federal Register." *See, e.g.*, 40 CFR 42.1235(b)(1)(ii)(A)(1)-(7). No such protections are afforded in the Good Neighbor Plan.

Finally, even if EPA's work plan process could be squared with the procedural requirements of the Clean Air Act, the current regulations do not provide sufficient clarity on the grounds on which the Administrator will determine whether a work plan "is complete, that is, whether the request contains sufficient information to make a determination" or fails "to satisfy the requirements of paragraphs (c) and (d)(1) through (3) of this section." Final Rule at 36,880; 40 CFR 52.43(d)(4)(i) and (v). As currently promulgated, the work plan process is so vague as to necessarily result in an arbitrary and capricious decision.

This work plan process was not proposed in the Proposed Rule and U. S. Steel had no notice that EPA was considering it prior to the Final Rule.[14] EPA must grant reconsideration to address the flaws in its work plan process for reheat furnaces and should, on reconsideration, remove reheat furnaces entirely from the Good Neighbor Plan.

X. The Work Plan Requirements for Reheat Furnaces Are Not Supported by the Record.

As noted in Ground for Reconsideration IX above, EPA did not propose a work plan process for reheat furnaces in the Proposed Rule. As a result, it would have been impracticable to comment on the target emission reductions and schedule in the Final Rule during public comment. As discussed in Ground for Reconsideration IX above, the reheat furnace requirements should be withdrawn entirely. If they are not, EPA must reconsider the requirements in these aspects of the Final Rule as well.

A. A Minimum 40% Reduction in NOx from Installation of Low-NOx Burners is Not Justified by the Record.

The Final Rule requires existing affected units to "install and operate low-NOx burners or equivalent alternative low-NOx technology designed to achieve at least a 40% reduction from baseline NOx emissions." 40 CFR 52.43(c). But EPA nowhere explains where this 40% target comes from. In the Proposed Rule, EPA proposed a 40% reduction through selective catalytic reduction ("SCR"). Proposed Rule at 20145, Table VII.C-3. Commenters, including U. S. Steel, submitted information showing that SCR is not technically feasible and its use was not supported by the record. *See, e.g.*, USS FIP Comments at 14-15. In the Final Rule, EPA has switched to reliance on low-NOx burners. Final Rule at 36,818. But EPA has not pointed to evidence that a 40% reduction is feasible for low-NOx burners. To the contrary, the Proposed Rule gives as an example a reheat furnace with low-NOx burners at Sterling Steel, which achieved less than a 20% reduction from the Ohio NOx RACT limit EPA used as its baseline for determining feasible NOx reductions. *See* Proposed Rule at 20145, Table VII.C-3.

As discussed in Ground for Reconsideration VIII above, EPA should exclude co-fired reheat furnaces from the Good Neighbor Plan entirely. If it does not, the 40% reduction goal presents an additional problem for these units. There is nothing in the record on their emission reduction potential from installation of low-NOx burners. Indeed, some process gases (like blast furnace gas) are by nature low-NOx. A 40% reduction is not demonstrated as feasible from these units. Combustion of coke oven gas introduces additional complications. NOx generation

[14] The only emission units subject to a work plan in the Proposed Rule were taconite furnaces in the metal ore mining industry. Proposed Rule at 20,182. This was based on a work plan process negotiated by EPA as a resolution to various rulemaking challenges to the 2016 Minnesota Regional Haze Federal Implementation Plan. A proposal to apply a specific work plan process to one industry is not notice that EPA is considering applying a different work plan process to different emission units in a different industry.

can vary significantly based on the nitrogen content of the process gas. This variability would have to be factored into determining an emission reduction potential for reheat furnaces that burn coke oven gas.

More generally, it is inconsistent with the work plan process for EPA to impose a minimum emission reduction requirement across all units. If the purpose of the work plan is to evaluate what is feasible for each unit, *see* 40 CFR 52.43(d)(3), the engineering evaluation of what is feasible should guide the emission reductions. As a result, if a work plan process is included following reconsideration, EPA should require installation of "cost effective emission controls" in accordance with the work plan, not a predetermined target reduction. *See, e.g.* Final Rule at 36,746.

B. The Schedule for Reheat Furnaces is Not Feasible.

The Final Rule requires owners and operators to submit a work plan by August 5, 2024. Final Rule at 36,879; 40 CFR 52.43(d)(1). The work plan approval process involves two rounds of EPA review, for completeness and approval, which will result in a final work plan by late 2024 or early 2025. *Id.*; 40 CFR 52.43(d)(4). Certification of installation is then due March 30, 2026. *Id.*; 40 CFR 52.43(g). This leaves approximately 15-16 months from work plan approval to completion of installation.

In U. S. Steel's experience, this is greatly insufficient. U. S. Steel has prepared a schedule for installation of low-NOx burners on the four reheat furnaces at U. S. Steel – Gary Works' 84" Hot Strip Mill. *See* Attachment A at Attachment 1, Appendix A. Even without the delay inherent in waiting for work plan approval, installation of low-NOx controls is expected to take until May 2027. Comparing this to EPA's assessment of the timing for compliance in the Timing Report, which was released with the Final Rule, it is clear that EPA underestimates the time required for initial evaluation and work plan approval, the likely time needed for permitting, and the time needed for fabrication and construction of pollution control requirement.

1. EPA's Timing Report Does Not Consider Work Plan Approval

The Timing Report assumes that implementation can begin in Month 3 (November 2023 for the Final Rule). Timing Report at 22. As noted above, however, EPA will not approve work plans until December 2023 or January 2024, assuming no delay on EPA's part in reviewing and approving work plans. Approval could take significantly longer if EPA is delayed or there is a need for supplemental information. Nowhere in the Timing Report does EPA appear to have considered the impact of this delay. Work plans are not mentioned at all and there is no time provided for their approval. Given EPA's assumption that all work can be completed in 15 months, the loss of even two months is significant and undermines EPA's compliance deadlines for reheat furnaces.

2. The Timing Report Underestimates Vendor Availability.

The Timing Report recognizes that vendor demand and capacity can introduce delays. Timing Report at 41. The Report appears to conclude that vendor capacity will not be a cause of delay, but U. S. Steel is already experiencing problems obtaining vendor quotes and finding and scheduling qualified union contractors. *See* Attachment A at ¶¶9 and 10. These issues are likely to get worse as EPA continues to implement additional Clean Air Act regulations that impose additional obligations on the iron and steel industry. *See id.* at ¶¶26-27. In addition, EPA's Timing Report only evaluates vendor availability for SCR and SNCR installation. Timing Report at 41-42. It does not assess the availability of low-NOx burner vendors for work on reheat furnaces, which is the technology EPA selected in the Final Rule. Here too U. S. Steel has found difficulty obtaining sufficient vendor quotes to proceed. Attachment A at ¶9.

3. The Final Rule Underestimates Permitting Times.

The Timing Report assumes that permitting can be completed in six months, despite noting that permitting can take over a year and may take longer. Compare Timing Report at 22 with ES-3. The Report does not reconcile these discrepancies. It appears to simply conclude that state permitting offices should be able to move quickly as long as they are not backlogged with other work. But EPA does not evaluate what other work States will be doing in the same timeframe. In Indiana, for example, EPA estimates that the Good Neighbor Plan will result in an additional 51 permit applications for non-EGU control installations alone. Timing Report at 44, Table 4-15. EPA assumes this will take 2,200 hours of work, which EPA assumes Indiana can compress into six months without any consideration of other permitting requirements that may arise in the same timeframe.

Combined, these delays make the schedule in the FIP highly unlikely. On reconsideration, if EPA retains a work plan process, EPA should revise the compliance schedules to allow sufficient time for work plan approval, engineering, permitting, installation, and testing prior to the certification date. At a minimum, this should allow for implementation through the 2027 ozone season.

XI. The Applicability Determination for Boilers at Iron and Steel Milles was Not a Logical Outgrowth of the Proposed Rule.

The Proposed Rule proposed to regulate boilers at iron and steel mills that "directly emits or has the potential to emit 100 tons per year or more of NOx." Proposed Rule at 20,181. EPA gave no notice that it was considering other applicability thresholds for boilers at iron and steel mills. In the Final Rule, however, EPA switched the applicability requirement to "a design capacity of 100 mmBtu/hr" and other restrictions. Final Rule at 36,884; 40 CFR 52.43(b). This was a significant departure, which EPA acknowledges captured more boilers than originally proposed. *See id.* at 36,819. EPA afforded the regulated community no opportunity to review the effects and applicability on these additional boilers until the Final Rule was released, however. This alone was improper. *Small Ref.*, 705 F.2d at 547 ("the final rule must be a logical outgrowth of the proposed rule") (quotations omitted). Furthermore, EPA has not adequately supported its contention that a boiler with a PTE of 100 tons is comparable to a boiler with a design capacity of 100 MMBtu/hr. A boiler's design capacity is not necessarily correlated with a boiler's design capacity. Frequently, based upon changes at facilities in which steam needs are reduced, operators do not use boilers near their design capacity. The assumption to correlate 100 tons to 100 MMBtu/hr is inappropriate.

XII. The Schedule for Boilers to Install Low-NOx Controls is Infeasible.

The Final Rule requires compliance testing to be completed no later than May 1, 2026. Final Rule at 36,885; 40 CFR 52.45(d)(1)(i). Since compliance testing requires 30 days, controls must be installed by April 2026. *Id.*; 40 CFR 52.45(d)(1). Even for states in which the Final Rule has not been stayed, this is not enough time to plan, design, approve, permit, install, and test new controls.

EPA's Timing Report estimates the Good Neighbor Plan will result in the installation of pollution controls on over 160 boilers in the same 31-month period. Timing Report at 32. Delays associated with stays of the SIP Disapproval will compress this period for many States.

For the iron and still industry, this will be on top of addressing reheat furnaces and several additional rules currently being promulgated. *See* Ground for Reconsideration VI above. The result is that the regulated community, permitting authorities, and vendors will likely be overwhelmed.

On reconsideration, EPA should reassess the timing needed to comply with the Good Neighbor Plan in light of the unenforceability of the Good Neighbor Plan in many states during judicial review of the SIP Disapproval, more realistic permitting times, and after additional consideration of the multiple obligations arising from other Clean Air Act regulations being promulgated by EPA.

XIII. The Heat Input Requirement for Boilers Does Not Adequately Provide for Outages of Sources of Process Gas.

EPA appropriately exempted from the Good Neighbor Plan a boiler that "receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels." Final Rule at 36,884; 40 CFR 52.45(b)(1). In the Final Rule, EPA added "in the previous ozone season," which helps clarify how heat input is to be averaged. *Id.* This addition, however, does not adequately accommodate outages for sources of process gas.

An extended idling of blast furnace operations, for example, can result in periods of blast furnace gas curtailment that could cause a boiler to exceed the 90% heat input threshold in a single ozone season. Bringing a co-fired boiler into the Good Neighbor Plan based on an exceedance of the 90% heat input requirement for a single ozone season, when it will return to normal operation shortly thereafter, makes little sense. Installing controls that are not technically or economically feasible to operate during normal operation is inconsistent with the record and will not be environmentally beneficial. The time it will take to plan, design, permit, install, and test controls will also take longer than the single year such a unit might need to operate on below 10% process gas.

On reconsideration, EPA should accommodate extended outages, either by allowing owners and operators to exclude from the heat input calculation short periods when alternative fuels are not available, or by providing a longer averaging period, such as the three-ozone season average the FIP provides for low-use boilers in 40 CFR 52.45(b)(2).

XIV. EPA Has Not Adequately Explained How Compliance Is Determined for Co-Fired Boilers.

The Final Rule exempts a boiler that "receives 90% or more of its heat input from coal, residual oil, distillate oil, natural gas, or combinations of these fuels." Final Rule at 36,884; 40 CFR 52.45(b)(1). If EPA concludes that they should be regulated, it must provide an appliable emission limit supported by the record. While U. S. Steel agrees that the introduction of process gases can and does interfere with the applicability and effectiveness of controls, it also affects the emission rates a unit can achieve. The Final Rule provides that heat input is to be calculated for natural gas, residual oil, distillate oil, and coal based on a per fuel basis. *Id.*; 40 CFR 52.45(c). EPA conducted no analysis of what emission limit can be achieved at a co-fired unit. If EPA intends to regulate these sources, it needs to have an applicable emission limit that is justified by the administrative record. The absence of any justification in the current record would render applying one of the above emission limits to combustion of process gas arbitrary and capricious.

XV. EPA Should Have Made Facility Wide Averaging Plans Available for Reheat Furnaces and Boilers.

In the Final Rule, EPA introduced the concept of a "Facility-Wide Averaging Plan" to "enable owners and operators of affected units to take costs, installation timing needs, and other considerations into account in deciding which [units] to control." Final Rule at 36,759-60. Facility-wide averaging was not proposed for any industry in the Proposed Rule. As a result, U. S. Steel did not have notice EPA was considering emission unit averaging for the Good Neighbor Plan. EPA made this option available in the Final Rule, but only for emergency engines in the Pipeline Transportation of Natural Gas industry. *Id.* EPA provided no justification for excluding other industries and sources from the option of using an averaging plan.

There is no practical justification for excluding reheat furnaces and boilers at iron and steel mills from being able to use of an averaging plan. U. S. Steel, for example, has long used averaging at emission units to facilitate permitting and maximize compliance efficiencies, including for boilers and reheat furnaces. *See* Attachment A at ¶¶29-31.

On reconsideration, EPA should allow reheat furnaces and boilers at iron and steel mills to take advantage of similar efficiencies and by being able to request a Facility-Wide Averaging Plan for boilers and reheat furnaces that are subject to the Final Rule.

Ground for Stay of the Good Neighbor Plan

EPA has authority to stay the Good Neighbor Plan both pending reconsideration and pending judicial review. First, a stay pending reconsideration can be granted for three months. 42 U.S.C. § 7607(d)(7). Second, EPA has authority under the APA to stay the Good Neighbor Plan pending judicial review.

I. EPA Should Stay the Good Neighbor Plan Pending Reconsideration.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). EPA may also issue a longer stay pending reconsideration under the APA. 5 U.S.C. § 705; 42 U.S.C. § 7607(d)(1). A stay pending reconsideration is justified here.

As discussed above, the Final Rule suffers from critical flaws. It was promulgated in violation of Clean Air Act requirements for many of the States to which it nominally applies. It is based on centrally-relevant information that was not subject to notice and comment, in violation of the procedural requirements of the Clean Air Act. It contains numerous omissions and contradictions that require clarification before the Good Neighbor Plan can reasonably be applied to reheat furnaces and boilers at iron and steel mills. And it overcontrols upwind State emissions, improperly shifting the burden of attainment the NAAQS from downwind States. These issues must be addressed before the FIP is enforced against owners and operators of affected units.

A stay of three months will allow EPA the time needed to reconsider the Good Neighbor Plan and incorporate the above grounds for reconsideration in a decision either to wholly withdraw the Final Rule or to publish a revised FIP that is legally and technically defensible. If additional time is needed, EPA should exercise its authority under the APA to extend the stay to allow sufficient time for full reconsideration and (as discussed below) judicial review.

A stay will also not unduly impact downwind states. The FIP cannot be enforced in ten states during the pendency of the current SIP Disapproval litigation, which will likely not be resolved for the duration of a reconsideration stay. At the same time, it will inequitably affect the remaining States subject to the Good Neighbor Rule, which is inconsistent with the spirit and intent of the Clean Air Act and EPA's stated intent in the Good Neighbor Rule itself to equitably distribute burdens and collectively address downwind impacts. Moreover, emission reductions from the iron and steel industry are not anticipated until 2026, long after a stay pending reconsideration will be completed. As a result, a stay pending reconsideration of the Good Neighbor Plan, and in particular the provisions of the Final Rule applicable to reheat furnaces and boilers at iron and steel mills, will have no impact on downwind attainment or maintenance of the NAAQS.

II. EPA Should Stay the Good Neighbor Plan Pending Judicial Review.

Under the APA, EPA may stay the effective date of the Good Neighbor Plan pending judicial review when "justice so requires." 5 U.S.C. §705. Multiple petitions have already been filed for judicial review, including petitions by Texas, Utah, Ohio, Indiana, West Virginia, and Oklahoma. More are likely, including a petition for judicial review that U. S. Steel is filing contemporaneously with this Petition. These cases are already spread across three circuits, and additional litigation may expand the number of courts further.

The effective date of the Final Rule is August 4, 2023, but the Good Neighbor Plan already cannot be applied in several states because of stays of the SIP Disapproval. A stay pending judicial review will therefore simply reflect the legal reality in those States. Further, the significant legal flaws in EPA's Final Rule discussed above make it likely that judicial review will result in a remand, if not vacatur, of the Good Neighbor Plan. As a result, a stay is strongly supported to avoid the unnecessary expenditure of EPA resources, State resources, and the resources of the public and regulated industries in addressing a FIP that is unlikely to sustained in its current form.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors also support issuance of a stay pending judicial review. Under this standard, the considerations for a stay are:

> 1. whether the stay applicant has made a strong showing that he is likely to succeed on the merits;
>
> 2. whether the applicant will be irreparably injured absent a stay;
>
> 3. whether issuance of the stay will substantially injure the other parties interested in the proceeding; and
>
> 4. where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

A. There is a High Likelihood of Success on the Merits.

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id.* (*quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the Good Neighbor Plan has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's Final Rule is based on circumstances that have been completely undermined by recent developments. It was not promulgated in accordance with the Clean Air Act. And was rushed to the point that it violates the core tenets of Cooperative Federalism on which the Clean Air Act, and the NAAQS program in particular, is based. For the iron and steel industry in particular, the FIP lacks a factual basis for supporting the regulation of reheat furnaces and boilers, or a justification for the requirements included in the Final Rule.

Because EPA's FIP is factually and procedurally flawed, and imposes requirements on reheat furnaces and boilers that are incomplete and in many states unenforceable, a challenge for judicial review is likely to prevail on the merits.

B. Absent a Stay, U. S. Steel Will Suffer Imminent Irreparable Harm.

Relevant factors for evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C.Cir.1985)).

The Final Rule poses substantial and imminent injuries to U. S. Steel. EPA itself warned owners and operators that they would need to "begin engineering and financial planning" as of the date of the *Proposed Rule* to be prepared to meet EPA's implementation timetable. Proposed Rule at 20,036; *see also* Unpublished Order, *Texas v. EPA*, Case No. 23-60069, ECF 269-1, at 22 (citing EPA's FIP timetable as ground for finding irreparable harm). Notwithstanding the fact that it is unreasonable to suggest that significant funds and resources should be used to implement a *proposed* rule that is subject to change (as the Good Neighbor Plan has changed), the Final Rule afforded no relief from this unreasonably short schedule. As discussed above, and in the attached Declaration of Alexis Piscitelli (Attachment A at ¶¶6-10), it allows insufficient time for design, permitting, and installation of controls; likely years less than what will be required. As a result, absent a stay, U. S. Steel cannot afford to wait before it must incur substantial costs on work plans that EPA does not have authority to impose, and on the design, permitting and installation of boiler and reheat furnace modifications that are unnecessary and may be subject to modification in a revised FIP.

As further discussed in the attached Declaration of Alexis Piscitelli, implementation of the Good Neighbor Plan is requiring U. S. Steel to incur immediate and significant costs. Attachment A at ¶¶3, 11-19. The work required by the Good Neighbor Plan will cost between $28 and $46 million at a single facility, excluding testing, monitoring, recordkeeping and reporting costs. Attachment A at ¶15. This cost far exceeds the $7,500/ton marginal cost assumed by EPA in the Final Rule. *See, e.g.* Final Rule at 36,733. These costs are not only unnecessary, they are being imposed without adherence to law. As a result, they constitute a significant irreparable harm to U. S. Steel. *See Thunder Basin Coal Co. v. Reich*, 510 U.S. 200, 220-21 (1994) ("complying with a regulation later held invalid almost always produces the irreparable harm of nonrecoverable compliance costs.") (Scalia, J., concurring in part and in the judgment). The compounding effect of these burdens on top of other regulations pending from EPA further exacerbates to significance of the harm to U. S. Steel. *See* Attachment A at ¶¶20-28.

C. A Stay Will Not Significantly Injury Other Parties.

Emissions reductions from the iron and steel industry are not anticipated to take effect until 2026 at the earlier in the Final Rule. As a result, there can be no appreciable injury to third parties pending judicial review. Moreover, because the Good Neighbor Plan cannot be applied in at least 10 states pending judicial review of EPA's SIP Disapproval, the Good Neighbor Plan is unlikely to apply until the 2024 ozone trading season even without a stay. As a result, a stay pending judicial review of the FIP will not result in any harm.

D. A Stay is in the Public Interest.

As courts have held, there is a public interest in enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay. As discussed above, EPA's Final Rule is without statutory authority and was promulgated through the inequitable exclusion of public participation on the information central to EPA's action. The result will be costly and needless public expenditures, both by U. S. Steel and the States that must act on the hundreds of permit applications the FIP requires, all while the Good Neighbor Plan is pending judicial review.

While it was an error for EPA to promulgate the Final Rule, EPA can ameliorate the harm of this error by staying the effect of the Good Neighbor Plan until the merits of the issues above can be fully evaluated and addressed.

Conclusion

Because circumstances arising after the close of the public comment period and before the time for judicial review demonstrate that the Good Neighbor Plan must be withdrawn, and because the FIP imposes significant obligations on the iron and steel industry that were not part of the Proposed Rule and that, with further comment, should have been corrected or amended, EPA is obligated to grant reconsideration and should withdraw the Final Rule, either in its entirely or as to reheat furnaces and boilers at iron and steel mills.

Further, to avoid the significant and irreparable harm to U. S. Steel arising from EPA's erroneous promulgation of the Final Rule, EPA should stay 40 CFR 52.43 of the Good Neighbor Plan and 40 CFR 52.45 as applied to the iron and steel industry pending reconsideration and pending judicial review.

Dated: August 4, 2023

Respectfully Submitted,

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Counsel for United States Steel Corporation

ATTACHMENT A – DECLARATION OF ALEXIS PISCITELLI

Before the United States Environmental Protection Agency

In re: Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 36,654 (June 5, 2023)	)))))	EPA Docket Nos. EPA–HQ–OAR–2021–0668 FRL–8670–02–OAR

Declaration of Alexis Piscitelli

I, Alexis Piscitelli, am over 18 years of age and make the following declaration pursuant to 28 U.S.C. § 1746:

1. I am the Senior Director Environmental for North American Flat Roll. at United States Steel Corporation ("U. S. Steel"), where I am responsible for ensuring compliance and reporting requirements are met in accordance with federal, state and local environmental permits and regulations. I have been employed by U. S. Steel for over 26 years and have advanced through various positions.

2. I am providing this declaration on behalf of U. S. Steel's Petition for Reconsideration and Stay of the United States Environmental Protection Agency's ("EPA's") Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards ("Good Neighbor Plan" or "Final Rule"), 88 Fed. Re. 36,654 (June 5, 2023).

3. As further explained in this declaration, the Final Rule will require immediate actions by U. S. Steel, including either curtailing the operation of reheat furnaces and boilers at U. S. Steel, or the expenditure of millions of

dollars to prepare now for implementation of the Good Neighbor Plan. Either or both of these actions will impose significant additional cost on U. S. Steel. Curtailing or the potential shutdown of the reheat furnaces would impact downstream units and ultimately customers. Curtailing the boilers will reduce electricity generation and increase the demand for outside purchased power, increasing costs and putting additional strain on the grid.

4. The Good Neighbor Plan also omits important flexibilities U. S. Steel uses to effectively and efficiently manage its environmental obligations.

5. This declaration is based on my personal knowledge of facts and information pertaining to U. S. Steel's business and the implications of EPA's Good Neighbor Plan. My knowledge is based on my history with U. S. Steel and analysis U. S. Steel has conducted of the Good Neighbor Plan.

I. <u>The Implementation Schedule for the Good Neighbor Plan is Insufficient</u>

6. In response to the Good Neighbor Plan, U. S. Steel developed a schedule for compliance with the regulatory obligations applicable to U. S. Steel – Gary Works' 84" Hot Strip Mill.

7. Based on our experience with projects of similar size and complexity, the assessment, design, permitting, and installation of low-NOx burners at all four furnaces will not be complete until May 2027, over a year beyond the May 2026 deadline for certification of completion of installation of low-

NOx technology in the Good Neighbor Plan. A copy of the project schedule is included as Appendix A to the attached Barr report (Attachment 1).

8. This schedule conservatively assumes that permitting can be completed in six months. Based on my experience, permitting can take significantly longer, leading to additional delays in completion.

9. U. S. Steel has also had difficulty obtaining vendor quotes for the required work. Consistent with U. S. Steel practice, our contractor, Barr, has attempted to obtain three separate vendor quotes for each technology U. S. Steel is analyzing. Only two firms provided full responses as of July 7, 2023. For one technology, selective non-catalytic reduction ("SNCR"), Barr contacted at least eight vendors but was able to obtain only two estimates. This further demonstrates the need for additional time for implementation of the Good Neighbor Plan, as we anticipate vendors will continue to experience backlogs and supply chain disruptions.

10. U. S. Steel has also had difficulty finding and scheduling qualified union contractors to work on significant projects at our facilities. For example, there are four reheat furnaces at Gary, each will require a significant outage to retrofit the equipment with low NOx burners or the equivalent. We anticipate the availability of qualified union workers will become even a

larger issue with multiple sources being impacted by the Good Neighbor Plan.

II. Implementation of the Good Neighbor Plan Requires U. S. Steel to Incur Immediate and Significant Costs

11. Among other things, the Good Neighbor Plan as promulgated imposes requirements on certain reheat furnaces at iron and steel mills, including the requirement to design a low-NOx burner or alternative low-NOx technology to achieve NOx emission reductions of at least 40% from baseline emission levels measured during performance testing that meets the criteria set forth in the rule. Additional obligations include emissions monitoring, recordkeeping, and reporting requirements.

12. While I agree that requiring a universal, hard limit for reheat furnaces is not appropriate, the requirement to design to meet a minimum 40% reduction of NOx from baseline is not appropriate because it does not take into account what is achievable for each reheat furnace, including what the baseline value actually is – whether, for example, it is 0.12 lb/MMBtu or 0.24 lb/MMBtu, what limits there are on the type of NOx reduction technology that can be used, what fuels the reheat furnace uses, what other pollution control technologies are already in place, or other factors that may make a minimum 40% reduction on some units technically or economically infeasible.

13. Baseline emission level performance testing cannot be completed without significant modification. For example, the reheat furnaces at Gary are very difficult to access. Testing equipment required to meet the USEPA specification cannot be used as currently configured. The facility will require engineered modification to provide access for personnel and equipment to conduct the required testing to establish a baseline for at least a 40% reduction design.

14. Based on the deadlines in the Good Neighbor Plan, which include submitting a completed work plan by August 5, 2024, U. S. Steel has already needed to begin project engineering and design and is already incurring significant costs to complete this work. Without a stay, and while the rule is subject to petitions for review, these costs are expected to substantially increase in the coming months with EPA's aggressive rule implementation schedule.

15. Based on an initial assessment of the costs supported by vendor quotes, I estimate installing low-NOx burners at the four reheat furnaces at U. S. Steel – Gary Works' 84" Hot Strip Mill will cost between approximately $28 million to more than $46 million. *See* Attachment 1 at Table 4-1. This does not include additional operating costs associated with the new equipment or

additional monitoring, performance testing, recordkeeping, and reporting costs associated with the Good Neighbor Plan.

16. This results in an estimated cost effectiveness of between $18,300 and $42,300 per ton NOx removed. Attachment 1 at Table 4-2. This far exceeds $3,656/ton average EPA includes in its Technical Memorandum to support the Final Rule. Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, EPA-HQ-OAR-2021-0668-0956, at Table 6 (March 15, 2023). It also far exceeds EPA's marginal cost threshold of $7,500/ton, the average cost-per-ton range for all non-EGUs of $939/ton to $14,595/ton, and even the $11,000/ton representative EGU retrofit cost EPA used for comparison in the Good Neighbor Plan. Final Rule at 36,746.

17. Without the Good Neighbor Plan, U. S. Steel would not need to incur these costs.

18. A stay of the FIP is necessary to avoid unnecessary costs until a final decision is reached on what obligations should apply to reheat furnaces and boilers at iron and steel mills.

19. Without a stay, U. S. Steel will incur significant and irreparable harm in reconfiguring the hot strip mill at Gary Works to allow for baseline performance testing and implementing the rule's requirements at the Company.

III. The Cumulative Burdens of the Good Neighbor Plan and Other Federal Requirements will Be Substantial and Could Have a Material Impact on Critical Infrastructure, National Security, and U. S. Steel Operations.

20. The U.S. steel industry is responsible for over $520 billion in economic output, supporting over 2 million jobs. It generates over $56 billion in tax revenues annually.

21. In a study conducted under Section 232 of the Trade Expansion Act of 1962 (19 U.S.C. §1862), the U.S. Department of Commerce determined that domestic steel production is essential for national security; and that domestic steel production depends on a healthy and competitive U.S. industry. (See https://www.bis.doc.gov/index.php/other-areas/office-of- technology-evaluation-ote/section-232-investigations).

22. The Cybersecurity & Infrastructure Security Agency has identified the iron and steel industry as a core critical infrastructure industry impacting transportation systems, electric power grid, water systems, and energy generation systems. (See https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/critical-infrastructure-sectors/critical-manufacturing-sector).

23. Implementation of the Final Rule upon the steel industry, when at the same time implementing new rules upon all facets of domestic steel

manufacturing also potentially jeopardizes thousands of good-paying USW jobs.

24. U. S. Steel is committed to continuing to work with federal partners to develop and implement scientifically sound regulations that effectively and demonstrably benefit the environment.

25. EPA's promulgation of overlapping Clean Air Act regulations without adequate consideration of their interaction undermines these efforts.

26. At the same time that EPA promulgated the Good Neighbor Plan, where it is mandating the installation of controls at reheat furnaces and boilers at iron and steel mills, EPA is proposing new MACT standards at taconite, integrated iron and steel facilities, and coke plants; as well as proposing revised NAAQS standards (e.g., PM2.5) which, combined, could have a material impact on the domestic steel industry, significantly affect the schedule for achieving these requirements, and result in a shortage of available technical support for implementation of these rules.

27. As noted above, U. S. Steel is already having difficulty obtaining qualified contractors and vendor quotes. These additional rules will exacerbate the problem.

28. EPA has also announced that it anticipates proposing reconsideration of the current ozone NAAQS in April 2024. As a result, EPA may be revising the

ozone NAAQS at the same time that the Good Neighbor Plan is requiring U. S. Steel to install pollution controls to address the current standards. Piecemealing these two rules, for which implementation will likely overlap, is problematic and inappropriate, as U. S. Steel could quite possibly be compelled to install additional or different controls on the same emission units following EPA's reconsideration. This would result in significant waste and could be avoided if EPA withdraws the Good Neighbor Plan and takes the two years allowed by the Clean Air Act for implementation of a revised FIP.

IV. <u>Importance of Facility-Wide Averaging to U. S. Steel</u>

29. U. S. Steel uses – and EPA, as well as other regulatory agencies, have allowed – emissions unit averaging where appropriate to effectively and efficiently satisfy regulatory obligations.

30. For example, at U. S. Steel – Great Lakes Work, boilers are permitted by boiler house, allowing averaging across multiple boilers serving the same or similar functions. At U. S. Steel – Granite City Works, Slab Furnace Nos 1-4 are subject to a single NOx limit, allowing averaging across all four reheat furnaces.

31. Allowing similar averaging in the Good Neighbor Plan would allow U. S. Steel to continue to benefit from the coordinated management of these emission units without sacrificing overall emissions performance.

V. <u>Conclusion</u>

32. In my opinion, the schedule set forth in the Good Neighbor Plan is not realistic and underestimates the time needed for compliance by at least a year. If emission units cannot achieve compliance by the scheduled deadlines and the deadlines are not stayed or extended, those emission units will be required to curtail operation. As a result. U. S. Steel is already required to incur substantial costs in order to prepare for the upcoming Good Neighbor Plan deadlines despite pending petitions for reconsideration and judicial review that may affect the applicability of the Good Neighbor Plan and the obligations that it imposes on reheat furnaces and boilers.

33. A stay of the Good Neighbor Plan will mitigate these harms.

I declare, under penalty of perjury, that the foregoing is true and correct.

Executed on August 4, 2023.

Alexis Piscitelli
Sr. Director Environmental – NAFR
United States Steel Corporation

ATTACHMENT 1

resourceful. naturally.
engineering and environmental consultants

Technical Memorandum

To: Louis Covelli (U. S. Steel)
From: Dane Jensen
Subject: 84" Hot Strip Mill Reheat Furnaces Good Neighbor Plan NO_X Emissions Controls Evaluation
Date: August 3, 2023
Project: 14451044.00
c: Thomas Ruffner, David Hacker, Kendra Jones, Christopher Hardin, Brett Tunno (U. S. Steel), Ryan Siats (Barr Engineering Co.)

Executive Summary

The U.S. Environmental Protection Agency (EPA) is taking action under the "good neighbor" or "interstate transport" provision of the Clean Air Act, with rulemaking that will take effect on August 4, 2023. The Good Neighbor Plan rulemaking under Docket ID No. EPA–HQ–OAR–2021-0668 requires emission reductions for affected facilities at U. S. Steel – Gary Works (USS), namely the 84" Hot Strip Mill (HSM) reheat furnaces (RHFs). The draft rulemaking requires a 40% NO_X reduction for RHFs. Barr was tasked with assessing the technical feasibility of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies, reviewing facility impacts of feasible NO_X controls including Low NO_X Burners (LNB), estimating costs and the cost effectiveness of feasible NO_X controls, and summarizing annual compliance testing costs.

The key findings of the HSM NO_X evaluation include:

- SCR is not technically feasible for the RHFs.
- SNCR is not technically feasible for the RHFs. There are operating conditions where the flue gas temperatures are expected to be outside the required SNCR reaction range.
- The compliance schedule in the draft rulemaking is insufficient to allow for installation of NO_X control technologies given requirements for baseline emissions testing, permitting, and availability of equipment vendors, mill wrights, engineering staff, etc.
- LNBs would require furnace upgrades, new flame safety equipment, and other facility modifications to accommodate this technology.
- The cost effectiveness of LNBs ranges from \$18,300 to \$42,300 per ton of NO_X removed.
- Annual performance testing costs for the RHFs are estimated to be \$13,300 to comply with the monitoring requirements of the Good Neighbor Plan.

Additional detail on each finding is summarized by Section below.

1 Good Neighbor Rule Regulatory Applicability

The regulatory applicability of the RHFs to the Good Neighbor Plan is described below.

40 CFR 52.43(b) states "*The requirements of this section apply to each new or existing reheat furnace at an iron and steel mill or ferroalloy manufacturing facility that directly emits or has the potential to emit 100 tons per year or more of NO_X on or after August 4, 2023, does not have low-NO_X burners installed, and is located within any of the States listed in § 52.40(c)(2), including Indian country located within the borders of any such State(s).*" The four reheat furnaces located at the Gary Works HSM all exceed a 100 tpy NO_X potential to emit, are in a state listed in §52.40(c)(2), and do not have LNB installed. Therefore, the RHFs are subject to the provisions of 40 CFR 52.43 and must achieve a 40% NO_X reduction from baseline conditions by the 2026 ozone season.

2 Technical Feasibility of SNCR and SCR

The technical feasibility of SNCR and SCR for the RHFs is discussed below. Figure 1 marks locations #1, #2, and #3 that will be referred to in the SNCR and SCR feasibility discussions for reference.

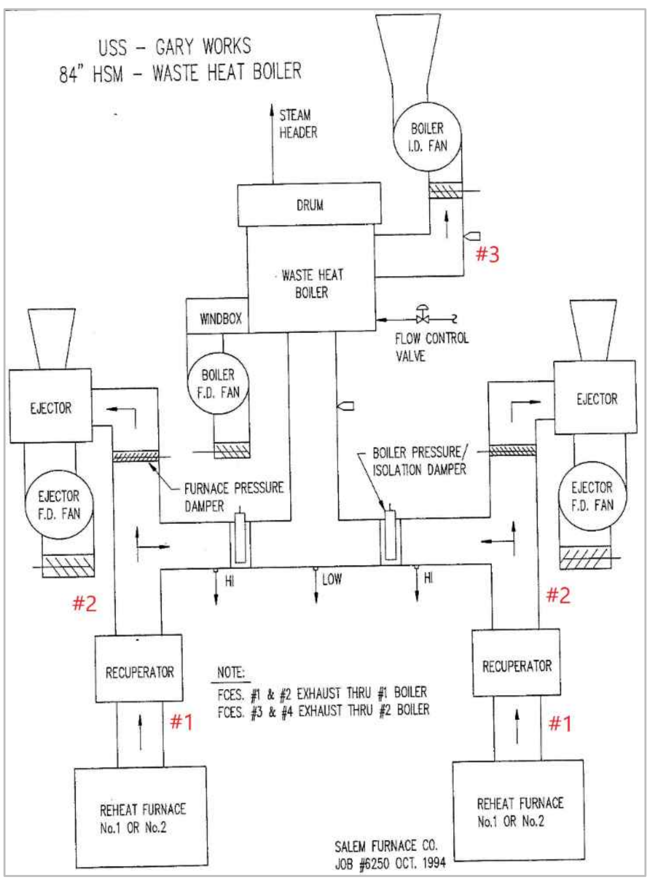

Figure 1 SNCR and SCR Feasibility Evaluation Locations

2.1 SNCR

SNCR involves the injection of ammonia or urea into a flue gas stream where the reagents react with NO_X to form elemental nitrogen. SNCR reactions require the flue gas temperature to be within a 1,600° Fahrenheit (F) to 2,100°F temperature range, with 1,800°F being ideal.

The only suitable SNCR injection location within the appropriate temperature location is #1, namely the outlet of the RHFs prior to the recuperator (refer to Figure 1). USS provided temperature data for this location and typically temperatures range from 1,600 to 1,930°F when operating. However, there are concerns about the viability of the data. A large portion of the data Barr received shows failed thermocouples or unreliable data trends. Figure 2 and Figure 3 show the Furnace 1 East and Furnace 4 East uptake temperatures, respectively, as an example of the sporadic data. It is unclear what represents "real" data vs. what is noise or failed thermocouples.

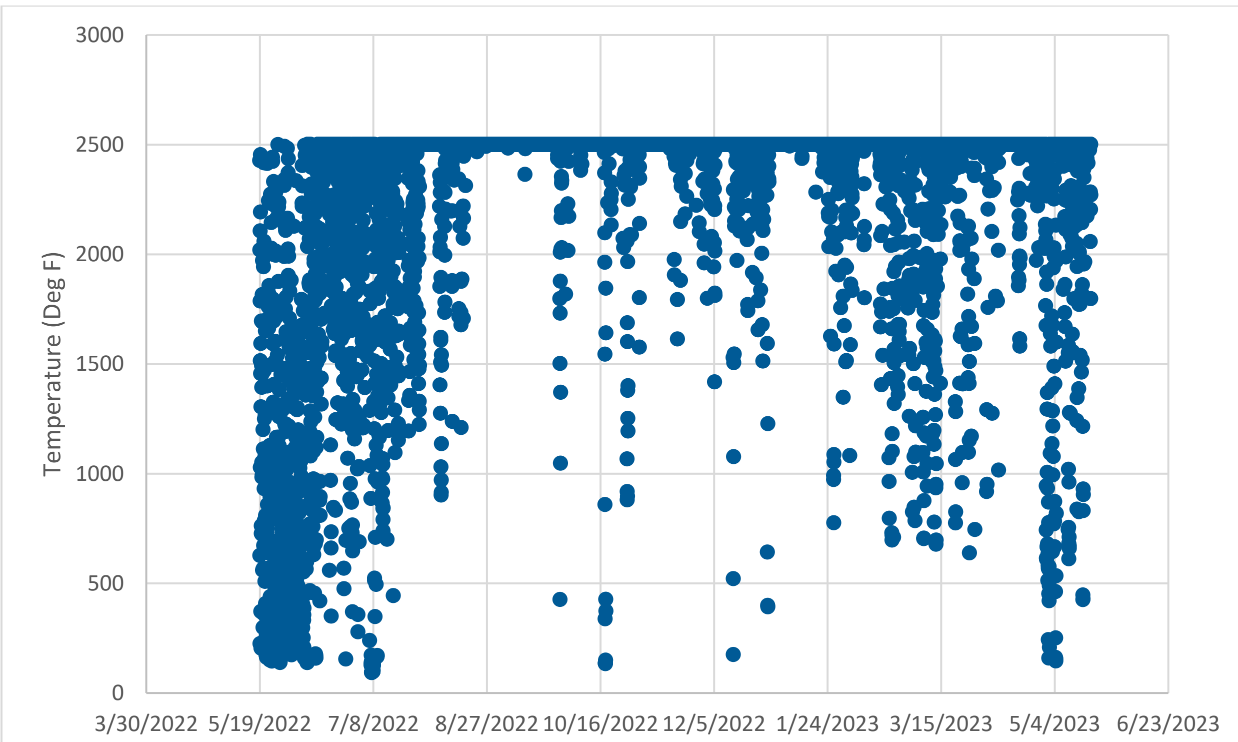

Figure 2 Furnace 1 East Uptake Temperatures Vs. Time

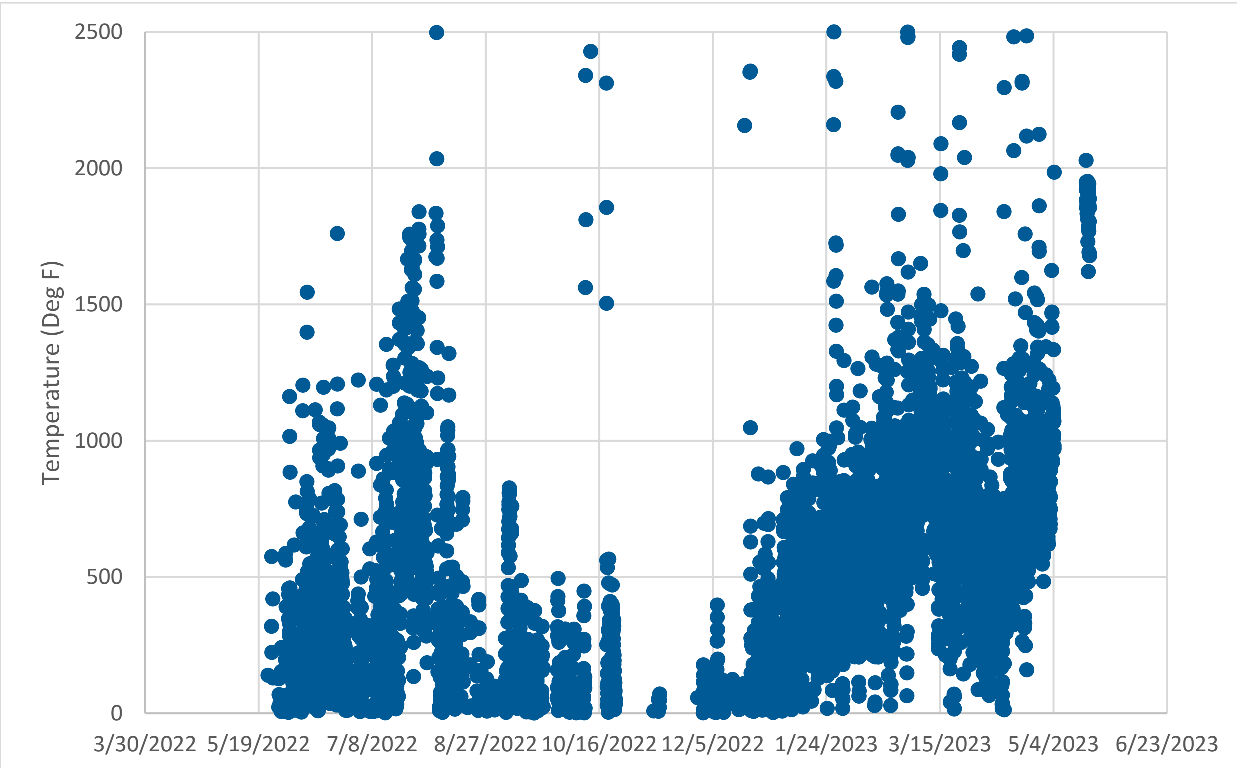

Figure 3 Furnace 4 East Uptake Temperatures Vs. Time

Another important design factor is residence time in the ducting with the high SNCR reaction temperatures. Vendors believe that there should be sufficient residence for SNCR in this application based on their review of USS data.

However, there are operating conditions where the flue gas fails to meet the minimum SNCR reaction temperatures, rendering SNCR infeasible. The Good Neighbor Plan requires a 40% NO_X reduction. Therefore, SNCR cannot sufficiently control NO_X at all times under all operating conditions. This is especially important during hot-standby conditions where fuel firing occurs, but USS expects the uptake temperatures to be below minimum SNCR requirements. In addition, a vendor stated that a feasibility study would be required to provide any sort of NO_X reduction guarantee. While SNCR is feasible during some operating scenarios, it cannot provide the needed consistent NO_X reduction for compliance purposes.

2.2 SCR

SCR reduces NO_X emissions with ammonia or urea injection in the presence of a catalyst. The catalyst enables the de- NO_X reactions to proceed at a lower temperature than SNCR. Most SCR catalysts must be at 450° F to 800° F for proper SCR operation based on vendor discussion and the EPA Control Cost Manual[1]. Each location for SCR from Figure 1 above was reviewed for SCR feasibility.

Location #1 – the temperatures at location #1 are too high (i.e., 1,600 to 1,930°F), so SCR is not technically feasible.

Location #2 – Waste heat temperatures exiting the recuperator are also too high for SCR. From May 2022 to May 2023, the average waste heat temperature was over 900°F, with temperature spikes exceeding 1,150°F. This is well above the optimal SCR range noted above. USS is aware that there are high-temperature applications of SCR on simple cycle combustion turbines in the temperature ranges of 850 to 1,000°F with vendors stating that 1,100°F would be the absolute maximum allowable temperature. However, high temperature SCR systems are significantly more costly due to special catalyst formulations and the catalyst life expectancy tends to shorten significantly, requiring more frequent changes that may inhibit production. As noted above, the high temperature spikes above 1,150°F would be above the maximum allowable temperature range making SCR infeasible for this location. In addition, high temperature SCR applications for simple cycle combustion turbines often use tempering air to reduce exhaust temperatures to suitable levels for normal SCR reaction temperatures. However, the use of tempering air is impractical for this application because the exhaust flows exiting the recuperator are quite large (i.e., more than 800,000 acfm) meaning that large amounts of make-up air would be required to sufficiently cool the exhaust flow to acceptable SCR reaction temperatures. The exhaust handling equipment cannot accommodate additional flow, and all the areas surrounding the recuperator outlet ductwork are extremely cramped with no reasonable way to incorporate additional cooling air, let alone provide sufficient residence time for mixing. In addition, tempering air would dilute the NO_X inlet concentration reducing the control equipment effectiveness. Further, SCR reactors for airflows of this magnitude are very large requiring a significant footprint. As noted above, the spacing surrounding this location is cramped, and it would be essentially impossible to shoe-horn a SCR reactor in place for this application. Also, it is not known if the existing building infrastructure could support additional weight above the furnace after the recuperator. Therefore, SCR is not technically feasible for location #2.

Location #3 – Exhaust temperatures at the exit of the waste heat boilers (WHBs) range from approximately 450 – 925°F. This mostly fits the SCR reaction temperature requirements. While the temperature profile may be satisfactory, it is impractical to install a SCR reactor at this location. Only a portion of the RHF exhaust is routed through the WHBs, meaning that the entire gas stream would not be treated. In addition, there are times when only the ejector stack is used, and no exhaust is routed through the WHBs. Therefore, there is no way to guarantee any consistent level of NO_X reduction with SCR at this location with incomplete or no RHF exhaust treatment, and would jeopardize compliance with the Good Neighbor Plan limits. Further, the variable exhaust flow through the WHBs would significantly complicate any SCR reactor design and may make it difficult to properly inject sufficient reagents and maintain proper mixing for all operating conditions. Further, spaces surrounding the outlet of the WHBs are very

[1] https://www.epa.gov/sites/default/files/2017-12/documents/scrcostmanualchapter7thedition_2016revisions2017.pdf

cramped leaving no viable location for a sizeable SCR reactor. Therefore, SCR is not practical or technically feasible for Location #3.

3 Facility Impacts of New NO_X Controls

According to discussions with vendors, LNBs will not impact production rates and burner vendors are willing to provide this guarantee. While not inherently challenging to LNBs, there are significant concerns about the schedule and the implementation period proposed in the Good Neighbor Plan (i.e., reductions must be achieved by the 2026 ozone season). As a result of this rulemaking, USS will need to conduct and obtain results from baseline emissions testing prior to submission of an application to modify the facility's operating permit to integrate either control technology. In addition, there are numerous facilities and industries nationwide that will be required to install controls for compliance. Therefore, USS is concerned that there will be insufficient resources for performance testing, permitting, engineering, equipment suppliers, equipment fabricators, and mill wrights that will allow USS to install necessary controls for compliance, much less all other affected facilities nationwide.

Schedule concerns have been evident during the development of this memo as Barr has attempted to obtain three separate vendor quotes. However, only two firms have provided costs for both LNB August 3, 2023. One LNB vendor failed to provide a quotation to USS even after stating that they could provide a new quote, so a 2020 cost estimate was scaled to 2023 dollars for this effort. This further demonstrates the need for additional time for implementation of this rule given vendor backlogs and unexpected supply chain disruptions. In addition, USS estimated a schedule based on engineering experience for the installation of LNBs (included as Appendix A to this memo) showing that there is insufficient time in the draft rule to install controls on all four RHFs and meet the compliance deadline.

Facility impacts for LNB installations are listed below:

- To accommodate new burners, USS will need to upgrade the furnace so that sufficient pressure can be maintained at the burners for safe and reliable operation.
- New National Fire Protection Association combustion safety equipment will be installed with new burners.
- Fuel pressure regulators will require modifications to increase fuel pressure at the burners.
- Some burner vendors require new combustion air fans complicating the overall design and installation.

4 Cost Estimates of New NO_X Controls

Barr and USS evaluated the costs for LNBs below for the RHFs. A detailed breakdown of capital equipment and installation costs has been prepared by USS for LNB based on vendor quotes and engineering experience. Table 4-1 summarizes capital costs for all furnaces for each vendor.

Table 4-1 Total Capital Investment Summary for LNB by Vendor (Total Cost for All Four Furnaces)

Vendor	Total HSM Capital Investment ($)
Vendor 1	$28,400,000
Vendor 2	$32,300,000
Vendor 3 (2020 Scaled Estimate)	$46,400,000

Detailed cost-effectiveness calculations for LNB are included in Appendix B. Table 4-2 summarizes the control costs for each LNB vendor.

Table 4-2 NO_X Control Cost Summary for LNB Vendors (Individual Furnace Cost)

Vendor	Total Capital Cost ($)	Annualized Cost ($/yr)	NO_X Reduction (tpy)	Cost Effectiveness ($/ton NO_X Removed)
Vendor 1	$7,112,000	$1,156,000	63	$18,300
Vendor 2	$8,073,000	$1,294,000	31	$42,300
Vendor 3 (2020 Estimate)	$11,590,000	$1,800,000	61	$29,500

5 Annual Performance Testing Cost Estimate

USS sought a performance testing bid for annual reheat furnace testing. The annual RHF performance testing costs are estimated to be $13,322. These costs and other miscellaneous costs such as recordkeeping and reported are not included in the cost-effectiveness evaluation in Appendix B.

6 Conclusions and Recommendations

The key findings of the HSM NO_X evaluation include:

- SCR is not technically feasible for the RHFs.
- SNCR is not technically feasible for the RHFs. There are operating conditions where the flue gas temperatures are expected to be outside the required SNCR reaction range.
- The compliance schedule in the draft rulemaking is insufficient to allow for installation of NO_X control technologies given requirements for baseline emissions testing, permitting, and availability of equipment vendors, mill wrights, engineering staff, etc.
- LNBs would require furnace upgrades, new flame safety equipment, and other facility modifications to accommodate this technology.
- The cost effectiveness of LNBs ranges from $18,300 to $42,300 per ton of NO_X removed.
- Annual performance testing costs for the RHFs is estimated to be $13,300 to comply with monitoring requirements of the Good Neighbor Plan.

Appendices

Appendix A

Estimated Low NOX Burner Installation Schedule

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	-11	-10	-9	-8	-7	-6	-5	-4	-3	-2	-1	0	1	2	3	4	5
	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Complete PAEE Paperwork																	
PAEE Approved																	
Engineering for emissions sampling infrastructure																	
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)																	
Air Permit Application Preparations																	
Baseline test complete																	
Obtain Air Permit - Permitting, Public Hearings, etc.																	
Perform detailed furnace study																	
Complete detailed design of burners																	
Complete burner installation scope and specification																	
Burner installation bids - price for each furnace separately																	
Complete AR Paperwork																	
AR Approved																	
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)																	
Order for furnaces 1-4 burners placed																	
Procure materials for burners																	
Fabrication of burners furnace 1																	
Shipment of burners for furnace 1																	
Place burner installation PO for furnace 1																	
Furnace 1 mobilization material procurement																	
Furnace 1 Outage																	
Furnace 1 Performance Testing																	
Lessons Learned Furnace 1 - installation specification updated																	
Fabrication of burners furnace 2																	
Shipment of burners for furnace 2																	
Place burner installation PO for furnace 2																	
Furnace 2 mobilization material procurement																	
Furnace 2 Outage																	
Furnace 2 Performance Testing																	
Lessons Learned Furnace 2 - installation specification updated																	
Fabrication of burners furnace 3																	
Shipment of burners for furnace 3																	
Place burner installation PO for furnace 3																	
Furnace 3 mobilization material procurement																	
Furnace 3 Outage																	
Furnace 3 Performance Testing																	
Lessons Learned Furnace 3 - installation specification updated																	
Fabrication of burners furnace 4																	
Shipment of burners for furnace 4																	
Place burner installation PO for furnace 4																	
Furnace 4 mobilization material procurement																	
Furnace 4 Outage																	
Furnace 4 Performance Testing																	

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	6	7	8	9	10	11	12	13	14	15	16	17
	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	18	19	20	21	22	23	24	25	26	27	28	29
	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

USS Gary Works - 84" HSM NOx Controls Evaluation
Appendix A - Estimated Low NOx Burner Installation Schedule

	30	31	32	33	34	36	36	37	38	39	40	41
	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Complete PAEE Paperwork												
PAEE Approved												
Engineering for emissions sampling infrastructure												
Partial install of emissions sampling infrastructure to allow baseline testing (scaffolding, umbilical piping)												
Air Permit Application Preparations												
Baseline test complete												
Obtain Air Permit - Permitting, Public Hearings, etc.												
Perform detailed furnace study												
Complete detailed design of burners												
Complete burner installation scope and specification												
Burner installation bids - price for each furnace separately												
Complete AR Paperwork												
AR Approved												
Completion of emissions sampling infrastructure (permanent platforms, ladders, etc.)												
Order for furnaces 1-4 burners placed												
Procure materials for burners												
Fabrication of burners furnace 1												
Shipment of burners for furnace 1												
Place burner installation PO for furnace 1												
Furnace 1 mobilization material procurement												
Furnace 1 Outage												
Furnace 1 Performance Testing												
Lessons Learned Furnace 1 - installation specification updated												
Fabrication of burners furnace 2												
Shipment of burners for furnace 2												
Place burner installation PO for furnace 2												
Furnace 2 mobilization material procurement												
Furnace 2 Outage												
Furnace 2 Performance Testing												
Lessons Learned Furnace 2 - installation specification updated												
Fabrication of burners furnace 3												
Shipment of burners for furnace 3												
Place burner installation PO for furnace 3												
Furnace 3 mobilization material procurement												
Furnace 3 Outage												
Furnace 3 Performance Testing												
Lessons Learned Furnace 3 - installation specification updated												
Fabrication of burners furnace 4												
Shipment of burners for furnace 4												
Place burner installation PO for furnace 4												
Furnace 4 mobilization material procurement												
Furnace 4 Outage												
Furnace 4 Performance Testing												

Appendix B

RHF LNB Control Costs

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - Cost Summary
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

NO_x Control Cost Summary (emissions and costs are for each furnace individually)

Control Technology	Control Eff %[a]	Controlled Emissions T/yr	Emission Reduction T/yr	Installed Capital Cost $	Annualized Operating Cost $/yr	Pollution Control Cost $/ton
Low NOx Burners (LNB) - Vendor 1	41%	89.6	63.1	$7,111,695	$1,155,629	$18,301
Low NOx Burners (LNB) - Vendor 2	20%	122.2	30.6	$8,072,695	$1,293,776	$42,343
Low NOx Burners (LNB) - Vendor 3	40%	91.7	61.1	$11,593,945	$1,799,972	$29,455

a - Calculated control efficiencies are not based on EPA certified performance test methods due to lack of access to appropriate test locations. Therefore, the control efficiencies may not appropriately represent what can be achieved from existing baseline conditions and the required reductions in the Good Neighbor Plan may not be feasible.

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - Utility and Chemical Supply Costs
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually **Study Year** 2023

2023

Item	Unit Cost	Units	Cost	Year	Data Source
Operating Labor	74	$/hr	60	2016	EPA SCR Control Cost Manual Spreadsheet
Maintenance Labor	74	$/hr			Assumed to be equivalent to operating labor
Other					
Sales Tax	7%			2020	Indiana sales tax rate
Interest Rate	8.25%			2023	Current prime bank rate
Operating Information					
Ozone Season Operating Hours	3,395	Hours			May 1st - September 30, adjusted for USS planned weekly maintenance outages
Annual Op. Hrs	8,100	Hours			USS Estimate
Utilization Rate	100%				Assumed
Design Capacity	600	MMBTU/hr			Permit listed duty
Equipment Life	20	yrs			Assumed
Plant Elevation	607	Feet above sea level			Plant elevation
	Baseline Emissions				
Pollutant	**Ton/Year**				
Nitrous Oxides (NOx)	152.8				Calculated
Baseline NOx performance	0.15	lb/MMBtu			Average of performance testing data
LNB NO_x Performance - Vendor 1	0.09	lb/MMBtu			Vendor guaranteed performance at 800F air preheat
Control efficiency - Vendor 1	41%				Calculated
LNB NO_x Performance - Vendor 2	0.12	lb/MMBtu			Vendor guaranteed performance at 800F air preheat
Control efficiency - Vendor 2	20%				Calculated
LNB NO_x Performance - Vendor 3	0.09	lb/MMBtu			2020 Quote LHV basis
Control efficiency - Vendor 3	40%				Calculated

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**7,111,695**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,072,321
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,155,629**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.09	89.6	63.1	18,301
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1. Refer to the *Vendor Summary* tab for Details
2. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
3. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment	Refer to *Vendor Summary* tab for Details	$	2,229,625
Installation	Refer to *Vendor Summary* tab for Details	$	1,494,250
Engineering	Refer to *Vendor Summary* tab for Details	$	304,320
Start-up and Commissioning	Refer to *Vendor Summary* tab for Details	$	381,000
Capital Spares	Refer to *Vendor Summary* tab for Details	$	137,500
Non-Capital Spares	Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work	Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC		**$**	**7,111,695**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	142,234
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	71,117
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	71,117
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	737,869
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,072,321**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,155,629**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 1
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			**8,100**	
			Utilization Rate:			**100%**	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**8,072,695**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,210,469
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,293,776**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.12	122.2	30.6	42,343
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1. Refer to the *Vendor Summary* tab for Details
2. Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor
3. Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment	Refer to *Vendor Summary* tab for Details	$	3,100,000
Installation	Refer to *Vendor Summary* tab for Details	$	1,629,250
Engineering	Refer to *Vendor Summary* tab for Details	$	288,945
Start-up and Commissioning	Refer to *Vendor Summary* tab for Details	$	309,500
Capital Spares	Refer to *Vendor Summary* tab for Details	$	180,000
Non-Capital Spares	Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work	Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC		**$**	**8,072,695**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	161,454
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	80,727
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	80,727
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	837,577
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,210,469**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,293,776**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 2
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			8,100	
			Utilization Rate:			100%	
Item	**Unit Cost $**	**Unit of Measure**	**Use Rate**	**Unit of Measure**	**Annual Use***	**Annual Cost**	**Comments**
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Note: emissions and costs are for each furnace individually

Desgin Capacity	600	MMBtu/hr
Expected Utiliztion Rate	100%	
Expected Ozone Season Operating Hours	3,395	Hours
Annual Interest Rate	8.3%	
Expected Equipment Life	20	yrs

CONTROL EQUIPMENT COSTS

Capital Costs							
Total Capital Investment (TCI) = DC + IC							**11,593,945**
Operating Costs							
Total Annual Direct Operating Costs		Labor, supervision, materials, replacement parts, utilities, etc.					83,307
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost					1,716,665
Total Annual Cost (Annualized Capital Cost + Operating Cost)							**1,799,972**

EMISSION CONTROL COST EFFECTIVENESS

Pollutant	**Baseline Emis. T/yr**	**Cont. Emis. lb/MMBtu**	**Cont Emis T/yr**	**Reduction T/yr**	**Cont Cost $/Ton Rem**
PM10				-	NA
Total Particulates				-	NA
Nitrous Oxides (NOx)	152.8	0.09	91.7	61.1	29,455
Sulfur Dioxide (SO_2)				-	NA

Notes & Assumptions

1 Refer to the *Vendor Summary* tab for Details

2 Assumed 0.1 and 0.5 hr/shift respectively for operator and maintenance labor

3 Controlled emission factor based on vendor estimated burner performance

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

CAPITAL COSTS			
Direct Capital Costs			
Equipment	Refer to *Vendor Summary* tab for Details	$	6,650,000
Installation	Refer to *Vendor Summary* tab for Details	$	1,838,000
Engineering	Refer to *Vendor Summary* tab for Details	$	243,945
Start-up and Commissioning	Refer to *Vendor Summary* tab for Details	$	147,000
Capital Spares	Refer to *Vendor Summary* tab for Details	$	150,000
Non-Capital Spares	Refer to *Vendor Summary* tab for Details	$	90,000
Cost Work	Refer to *Vendor Summary* tab for Details	$	2,475,000
Total Capital Investment (TCI) = DC + IC		**$**	**11,593,945**

OPERATING COSTS			
Direct Annual Operating Costs, DC			
Operating Labor			
Operator	73.79	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr	7,471
Supervisor	15%	15% of Operator Costs	1,121
Maintenance (2)			
Maintenance Labor	73.79	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr	37,357
Maintenance Materials	100%	of maintenance labor costs	37,357
Utilities, Supplies, Replacements & Waste Management			
NA	NA		-
NA	NA		-
Total Annual Direct Operating Costs			**83,307**
Indirect Operating Costs			
Overhead	60%	of total labor and material costs	49,984
Administration (2% total capital costs)	2%	of total capital costs (TCI)	231,879
Property tax (1% total capital costs)	1%	of total capital costs (TCI)	115,939
Insurance (1% total capital costs)	1%	of total capital costs (TCI)	115,939
Capital Recovery	10%	for a 20- year equipment life and a 8.25% interest rate	1,202,923
Total Annual Indirect Operating Costs		Sum indirect oper costs + capital recovery cost	**1,716,665**
Total Annual Cost (Annualized Capital Cost + Operating Cost)			**1,799,972**

U. S. Steel Gary Works
Good Neighbor Plan NOx Evaluation
Appendix B - NOx Control - Low NOx Burners (LNB) Vendor 3
84" Hot Strip Mill Reheat Furnaces No. 1 through No. 4

Capital Recovery Factors		
Primary Installation		
Interest Rate	8.25%	
Equipment Life	20	years
CRF	0.1038	

Operating Cost Calculations			**Annual hours of operation:**			8,100	
			Utilization Rate:			100%	
	Unit	**Unit of**	**Use**	**Unit of**	**Annual**	**Annual**	**Comments**
Item	**Cost $**	**Measure**	**Rate**	**Measure**	**Use***	**Cost**	
Operating Labor							
Op Labor	73.79	$/Hr	0.1	hr/8 hr shift	101	7,471	$/Hr, 0.1 hr/8 hr shift, 8100 hr/yr
Supervisor	15%	of Op.			NA	1,121	15% of Operator Costs
Maintenance							
Maint Labor	73.79	$/Hr	0.5	hr/8 hr shift	506	37,357	$/Hr, 0.5 hr/8 hr shift, 8100 hr/yr
Maint Mtls	100	% of Maintenance Labor			NA	37,357	100% of Maintenance Labor

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Burners Ultra-Low Nox Burners
New burners will fit inside existing bodies (plug & play)

Flame safety included:
Covert the soak zone to a supervised system to bring the soak zone above auto-ignition
16 New Soak Burners, Direct Spark Ignition, Flame Rod, Transformer, Ignition Cable, Necessary Gas and Air Valves
Double Block Valves for 40 Soak Burners
New NFPA Compliant Main Fuel Train
New NFPA Compliant Pilot Train - Required for Cold Start Operation in Bottom Heat.
To Accommodate Flame Supervision in the Soak Section and Cold Start Capabilities in the Bottom Heat Section.

Included in cost scope:
Upgrades to combustion air system and recuperators
NG piping replacement as required - restricted piping... coke oven gas remediations
Upgrades to Level 0/1 components
Refractory

Task	Item	Vendor	Estimate		Contingency			Amount	
1000	**Equipment**							**$**	**8,918,500**
	Burners	VENDOR 1	$	7,320,000	5%	$	366,000	$	7,686,000
	Emissions Sampling/Testing Infrastructure		$	400,000	20%	$	80,000	$	480,000
	Peripheral Control Equipment		$	200,000	20%	$	40,000	$	240,000
	Refractory/Piping Materials		$	300,000	20%	$	60,000	$	360,000
						$	152,500	$	152,500
1100	**Installation**							**$**	**5,977,000**
	Burners		$	3,800,000	20%	$	760,000	$	4,560,000
	Emissions Sampling/Testing Infrastructure		$	850,000	30%	$	255,000	$	1,105,000
	Model/Pie Updates		$	90,000	30%	$	27,000	$	117,000
	Level 1 Updates		$	150,000	30%	$	45,000	$	195,000
2900	**Engineering**							**$**	**1,217,280**
	Impact Analysis and Study		$	53,600	5%	$	2,680	$	56,280
	Technical Support for Impact Study		$	20,000	5%	$	1,000	$	21,000
	Detailed Furnace Study	VENDOR 1	$	230,000	5%	$	11,500	$	241,500
	Design of Emissions Sampling/Testing Infrastructure		$	150,000	20%	$	30,000	$	180,000
	Installation Specification Development		$	150,000	20%	$	30,000	$	180,000
	Constructability		$	60,000	20%	$	12,000	$	72,000
	Furnace Model Modifications	VENDOR 1	$	60,000	20%	$	12,000	$	72,000
	Level I Design - Burners/Flame Safety/Consulting		$	90,000	20%	$	18,000	$	108,000
	As-Built Drawings - MOC		$	160,000	20%	$	32,000	$	192,000
	Drawing Management		$	90,000	5%	$	4,500	$	94,500
2910	**Start-up and Commissioning**							**$**	**1,524,000**
	Field Supervision	VENDOR 1	$	780,000	20%	$	156,000	$	936,000
	Scheduling and Cost Control		$	90,000	20%	$	18,000	$	108,000
	Construction Management		$	400,000	20%	$	80,000	$	480,000
3000	**Capital Spares (>$10,000)**							**$**	**550,000**
	Capital Spares		$	500,000	10%	$	50,000	$	550,000
5000	**Non-Capital Spares (<$10,000)**							**$**	**360,000**
	Spare Parts		$	300,000	20%	$	60,000	$	360,000
6000	**Cost Work**							**$**	**9,900,000**
	Cost Work		$	8,250,000	20%	$	1,650,000	$	9,900,000

CAPITAL ESTIMATE	**$**	**18,186,780**
EXPENSE ESTIMATE	**$**	**10,260,000**
TOTAL ESTIMATE	**$**	**28,446,780**

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Vendor 2 Estimate

Burners New burners
All four burner walls will be reworked to incorporate the necessary converging tile for the required air injection velocity.
Need to replace combustion air fans

Flame safety included:
Four auxiliary side fired burners to bring the soak zone above auto-ignition.
Replacement of the burner bodies in the bottom heat zone to accept a fully compliant piloted ignition system
Addition of injectors only to the top heat and top and bottom preheat zones that will be interlocked to 1400 °F permissive.
Proof of purge and low fire switches will be installed on existing air metering orifice plates
Safety PLC is included to perform the necessary flame monitoring and natural gas path select functionality

Included in cost scope:
Upgrades to combustion air system and recuperators
NG piping replacement as required - restricted piping... coke oven gas remediations
Upgrades to Level 0/1 components
Refractory

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 12,400,000**
	Burners	VENDOR 2	$ 10,400,000	5%	$ 520,000	$ 10,920,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Peripheral Control Equipment (Safety PLC Provided)		$ 125,000	20%	$ 25,000	$ 150,000
	Refractory/Piping Materials		$ 600,000	20%	$ 120,000	$ 720,000
	Combustion Air Fans		$ 100,000	30%	$ 30,000	$ 130,000
1100	**Installation**					**$ 6,517,000**
	Burners		$ 4,000,000	20%	$ 800,000	$ 4,800,000
	Combustion Air Fans		$ 300,000	30%	$ 90,000	$ 390,000
	Emissions Sampling/Testing Infrastructure		$ 800,000	30%	$ 240,000	$ 1,040,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 125,000	30%	$ 45,000	$ 170,000
2900	**Engineering**					**$ 1,155,780**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Detailed Furnace Study	VENDOR 2	$ 150,000	20%	$ 30,000	$ 180,000
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	VENDOR 2	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 1,238,000**
	Field Supervision	VENDOR 2	$ 500,000	30%	$ 150,000	$ 650,000
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 720,000**
	Capital Spares (combustion air fan added)		$ 600,000	20%	$ 120,000	$ 720,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 22,030,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 32,290,780**

USS Gary - HSM NOx Controls Evaluation
Appendix B - Low NOx Burner Cost Estimates (All Furnaces)
Vendor 1 Estimate

Vendor 3 Estimate

Burners New burners
Moderate shell steel and refractory port modifications
The combustion air blower will be replaced with higher pressure fans
existing recuperator, zone orifice plates and flow control valves.
Burner drop ductwork will need to be modified as required to connect to the new burners.
New burner expansion joints will be provided along with new burner isolation valves.
Gas piping from the gas train to the burners will remain in place, and existing orifice plates and flow control valves will remain in service
Piping modification to suit the new burners will be made at the burner drops
A new level 1 control system, including new PLC hardware, remote I/O panels, HMI screens is included.

Flame safety included:
Gas train for the furnace must be modified to comply with the latest NFPA-86 standards
The combustion system will be designed to use the top and bottom heat zones as the light-up zones
The top and bottom preheat zones will be ignited when the zones are above auto-ignition bypass temperature
The furnace will be provided with new purge and safety checks for proper ignition sequence as mandated by the NFPA.
Ignition burners will have spark ignited pilot burners with UV detector type flame supervision
A burner management system panel will be included to house the electronic components

Task	Item	Vendor	Estimate	Contingency		Amount
1000	**Equipment**					**$ 26,600,000**
	Burners (Flame Safety Included, comb air fans)	Vendor 3	$ 24,000,000	5%	$ 1,200,000	$ 25,200,000
	Emissions Sampling/Testing Infrastructure		$ 400,000	20%	$ 80,000	$ 480,000
	Refractory/Piping Materials (burner walls need to be reworked)		$ 800,000	15%	$ 120,000	$ 920,000
1100	**Installation**					**$ 7,352,000**
	Burners		$ 5,000,000	20%	$ 1,000,000	$ 6,000,000
	Emissions Sampling/Testing Infrastructure		$ 800,000	30%	$ 240,000	$ 1,040,000
	Model/Pie Updates		$ 90,000	30%	$ 27,000	$ 117,000
	Level 1 Updates		$ 150,000	30%	$ 45,000	$ 195,000
2900	**Engineering**					**$ 975,780**
	Impact Analysis and Study		$ 53,600	5%	$ 2,680	$ 56,280
	Technical Support for Impact Study		$ 20,000	5%	$ 1,000	$ 21,000
	Design of Emissions Sampling/Testing Infrastructure		$ 150,000	20%	$ 30,000	$ 180,000
	Installation Specification Development		$ 150,000	20%	$ 30,000	$ 180,000
	Constructability		$ 60,000	20%	$ 12,000	$ 72,000
	Furnace Model Modifications	Vendor 3	$ 60,000	20%	$ 12,000	$ 72,000
	Level I Design - Burners/Flame Safety/Consulting		$ 90,000	20%	$ 18,000	$ 108,000
	As-Built Drawings - MOC		$ 160,000	20%	$ 32,000	$ 192,000
	Drawing Management		$ 90,000	5%	$ 4,500	$ 94,500
2910	**Start-up and Commissioning**					**$ 588,000**
	Scheduling and Cost Control		$ 90,000	20%	$ 18,000	$ 108,000
	Construction Management		$ 400,000	20%	$ 80,000	$ 480,000
3000	**Capital Spares (>$10,000)**					**$ 600,000**
	Capital Spares (combustion air fan added)		$ 500,000	20%	$ 100,000	$ 600,000
5000	**Non-Capital Spares (<$10,000)**					**$ 360,000**
	Spare Parts		$ 300,000	20%	$ 60,000	$ 360,000
6000	**Cost Work**					**$ 9,900,000**
	Cost Work		$ 8,250,000	20%	$ 1,650,000	$ 9,900,000

CAPITAL ESTIMATE	**$ 36,115,780**
EXPENSE ESTIMATE	**$ 10,260,000**
TOTAL ESTIMATE	**$ 46,375,780**

ATTACHMENT B – PETITION FOR RECONSIDERATION AND STAY OF THE FINAL RULE: AIR PLAN DISAPPROVALS; INTERSTATE TRANSPORT OF AIR POLLUTION FOR THE 2015 8-HOUR OZONE NATIONAL AMBIENT AIR QUALITY STANDARDS, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 FED. REG. 9,336 (FEBRUARY 13, 2023)

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April 14, 2023

VIA E-MAIL AND FEDERAL EXPRESS

Michael Regan, Administrator
Environmental Protection Agency
Office of the Administrator, Mail Code 1101A
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Petition for Reconsideration and Stay of the Final Rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023)

Dear Administrator Regan:

On behalf of our clients, ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively the “Minnesota Good Neighbor Coalition”), please find enclosed a petition for reconsideration and stay of the disapproval of “prong 2” of Minnesota’s State Implementation Plan (“SIP”) in the United States Environmental Protection Agency’s final rule: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, EPA-HQ-OAR-2021-0663; EPA-R05-OAR-2022-0006; 88 Fed. Reg. 9,336 (February 13, 2023).

Please contact me with any questions you may have.

Sincerely,

/s/ Douglas A. McWilliams
Douglas A. McWilliams

cc: Olivia Davidson
Debra Shore
Gautam Srinivasan
Thomas Uher

Before the United States Environmental Protection Agency

In re: Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023)	))))))	EPA Docket Nos. EPA–HQ–OAR–2021–0663; EPA–R05–OAR–2022–0006; FRL–10209–01–OAR

Petition for Reconsideration and for Stay of the Air Plan Disapprovals for Interstate Transportation of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards

ALLETE, Inc. d/b/a Minnesota Power; Northern States Power Company – Minnesota d/b/a/ Xcel Energy; Great River Energy; Southern Minnesota Municipal Power Agency; Cleveland-Cliffs, Inc.; and United States Steel Corporation (collectively "Petitioners") respectfully request that the United States Environmental Protection Agency ("EPA") reconsider and stay the portion of its final rule Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 Fed. Reg. 9336 (February 13, 2023) (the "SIP Disapproval") that disapproves Minnesota's state implementation plan ("SIP") for interstate transport for "prong 2" of Clean Air Act ("CAA") § 110(a)(2)(D)(i)(I), 42 U.S.C. § 7410(a)(2)(D)(i)(I).

Minnesota is uniquely situated in the SIP Disapproval. In EPA's February 13 action, Minnesota's SIP was approved for "prong 1"[1] based on EPA's finding that Minnesota does not contribute significantly to nonattainment in any downwind state. Minnesota's SIP was disapproved for "prong 2," with EPA finding that Minnesota was linked to interference with maintenance of a single downwind maintenance-only receptor. EPA has subsequently found in its promulgation of an ozone transport federal implementation plan ("FIP") that Minnesota was not linked to any downwind non-attainment or maintenance-only receptor when modeled for 2026.

Based on the best evidence available in 2018 when Minnesota submitted its SIP to EPA for approval (and on April 1, 2020 when EPA had a statutory obligation to approve or deny the Minnesota SIP), Minnesota was ***not*** linked to interference with attainment or maintenance in any downwind state. But, EPA did not timely act on the Minnesota SIP, and then it moved the goal posts. Based on new modeling and emission data EPA developed years later, (the "2016v2" modeling platform) EPA proposed to find that Minnesota was linked to two downwind maintenance-only receptors due to a modeled impact of less than 1 ppb at each receptor. In the

[1] As discussed on page 4 *infra*, EPA has divided the Good Neighbor obligation set out in Clean Air Act ("CAA") § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D), into two "prongs." The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2."

final SIP Disapproval, EPA again revised its emissions data and modeling (the "2016v3" modeling platform) and now finds that Minnesota is linked in 2023 to only a single maintenance-only monitor, at a maximum contribution of 0.85 ppb. Further, EPA has since released updated modeling results for 2026 that show that this same monitor will be in attainment without any material reduction of emissions from Minnesota. As a result, after five years of updates, EPA's modeling results support the same conclusion that Minnesota reached in 2018, namely that additional emissions reductions are not needed to prohibit emissions in Minnesota that will contribute significantly to nonattainment, or interfere with maintenance of, the 2015 8-hour ozone NAAQS in any downwind state. We ask that EPA grant this petition for reconsideration to do what it should have done in 2018—Approve the Minnesota SIP.

The approvability of Minnesota's original SIP submittal is corroborated by two additional pieces of information that were not available during the public comment period for the proposed SIP disapproval or prior to EPA's release of its 2016v3 modeling in 2023. First, EPA's 2016v3 emissions inventory materially overstates Minnesota's 2023 NOx emissions; for example, it incorrectly assumes over 2,800 tons of NOx from an electric generating facility that has been idled since 2019 and is projected to have zero emissions in 2023. By merely correcting the projected actual NOx emissions, Minnesota has already achieved more NOx reductions than EPA's FIP would require of Minnesota. This effectively confirms Minnesota's step 3[2] conclusion in its 2018 SIP that no additional permanent or enforceable measures were needed beyond those already implemented by the state.[3]

Second, as EPA has recognized, its CAMx modeling is subject to significant bias in areas of complex meteorology, including the water/land interface occurring at the sole maintenance monitor that EPA has linked to Minnesota emissions. While EPA released with the final SIP Disapproval a review of this localized bias risk for southern Lake Michigan, that review was materially flawed and does not address the significant over-prediction bias occurring on the precise days EPA selected for use in evaluating Minnesota's SIP. As a result, EPA's general conclusion that adjusting for bias will not affect the outcome of its SIP reviews, does not apply to its review of the Minnesota SIP. To the contrary, adjusting for material bias results in the sole maintenance-only monitor to which Minnesota was linked by EPA becoming an attainment monitor in 2023. In other words, eliminating high-bias days alone completely addresses EPA's objection to Minnesota's 2018 SIP and eliminates Minnesota at Step 1 of EPA's four-step analysis.

Reconsideration is appropriate to make the above corrections to the emissions inventory and to account for modeling bias. After incorporating this new material information into the SIP analysis, we believe that EPA will conclude as we have that Minnesota's original 2018 SIP determination that it is not having a downwind impact on attainment or maintenance that requires additional permanent and enforceable measures was correct and warrants approval of

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[2] *See* page 4 *infra* for the list of four steps in EPA's 4-step framework for evaluating Good Neighbor SIP submissions.

[3] *See* Minnesota's 110(a)(1) and 110(a)(2) "Infrastructure" State Implementation Plan requirements for the National Ambient Air Quality Standards for Ozone, Promulgated in 2015, EPA-R05-OAR-2022-0006-0005, at 12 (October 1, 2018) ("2018 SIP").

the Minnesota SIP. Reconsideration is also appropriate to address a significant procedural flaw in the finalization of the SIP Disapproval. Specifically, the SIP Disapproval relies on information that was not available to EPA, Minnesota, or any other interested parties until 2023, well past the period for Minnesota's SIP submission and EPA's statutory deadline to approve Minnesota's SIP. While EPA has an obligation to use the best available evidence in making its regulatory decisions, that obligation is not unbounded and cannot be used to circumvent the procedures set forth in the Clean Air Act. When Minnesota timely submitted a SIP that is approvable based on the information known at the time, EPA had an obligation to approve the SIP. The Act does not allow EPA unfettered discretion to delay approval until new information becomes available, and then move the goalposts. For States that have done their part to invest resources in developing a timely and approvable SIP, EPA has a statutory obligation to act. EPA may still consider new scientific data and modeling after the statutory deadline, but there is a separate administrative process available to EPA that respects the State's SIP process. Minnesota should have an approved SIP and EPA should be considering whether new information is sufficiently material to require a "SIP call" pursuant to CAA § 110(k)(5), 42 U.S.C. § 7410(k)(5), to give Minnesota the opportunity to revise its SIP given the new available information. Having chosen to use this new information to disapprove prong 2 of Minnesota's SIP instead, EPA deprived Petitioners, the State, and other interested parties of significant procedural protections and opportunities for public input that were required by the Clean Air Act. Granting reconsideration allows EPA the opportunity to cure the procedural flaw that its final action is based on material information that has not been subject to the notice and comment process.

Given that new information was made available after the close of the public comment period, but before the time for judicial review, that such information actually undermines EPA's basis for disapproving prong 2 of Minnesota's 2018 SIP in the SIP Disapproval, and reconsideration would address the harms caused by significant procedural defects in the SIP Disapproval, Petitioners respectfully request that EPA grant reconsideration for the purpose of reviewing this new information and approving prong 2 of Minnesota's 2018 SIP.

Further, since the disapproval of prong 2 of Minnesota's SIP, and the continued implementation of EPA's subsequently-issued FIP, will cause irreparable harm to Petitioners, we request that EPA grant a stay of the disapproval of prong 2 of Minnesota's SIP pending reconsideration and pending judicial review, which will also address the irreparable harm caused by EPA's FIP.

I. Background

On October 1, 2015, EPA promulgated a revised primary and secondary 8-hour ozone NAAQS of 70 ppb. This created a requirement under the CAA for states to submit revised SIPs to EPA by October 1, 2018.[4] SIPs were required to meet the applicable requirements of CAA § 110(a)(2), 42 U.S.C. § 7410(a)(2), including an obligation, sometimes referred to as a "Good Neighbor" obligation, that the SIPs:

[4] 42 U.S.C. § 7410(a)(1).

> (D) Contain adequate provisions—
>
> > (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—
> >
> > > (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standard, …

42 U.S.C. § 7410(a)(2)(D). The obligation to prohibit sources from emitting air pollutants in an amount which will "contribute significantly to nonattainment" is sometimes referred to as "prong 1," and the obligation to prohibit sources from emitting air pollutants in an amount which will "interfere with maintenance" as "prong 2," of the Good Neighbor obligation.

While EPA has never promulgated regulations imposing more specific interstate transport requirements than what is contained in the statutory text, EPA has developed a 4-step framework that it stated the agency would use to evaluate a state's compliance with its Good Neighbor obligation. Namely:

(1) Identify monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS (i.e., nonattainment and/or maintenance receptors);

(2) identify states that impact those air quality problems in other (i.e., downwind) states sufficiently such that the states are considered ''linked'' and therefore warrant further review and analysis;

(3) identify the emissions reductions necessary (if any), applying a multifactor analysis, to eliminate each linked upwind state's significant contribution to nonattainment or interference with maintenance of the NAAQS at the locations identified in Step 1; and

(4) adopt permanent and enforceable measures needed to achieve those emissions reductions.[5]

Minnesota took a notably conservative approach in its SIP. First, in EPA's Transport Memo, EPA recognized that its four-step framework was not binding, and offered that states "have flexibility to follow this framework or develop alternative frameworks."[6] Despite this flexibility, Minnesota adopted EPA's framework for its SIP.[7] Second, EPA made clear, in the

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[5] *See* Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I), https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf at 2-3 (March 27, 2018) ("Transport Memo").

[6] *Id.*

[7] 2018 SIP at 5.

Transport Memo and in a separate memorandum published later that year, that states did not need to adopt EPA's suggested 1% threshold for determining significant contributions and interference with maintenance at step 2.[8] Here too, Minnesota did not exercise this flexibility, and chose instead to use EPA's preferred approach.[9] Third, EPA guidance offered states flexibility regarding how to determine which downwind monitors should be considered maintenance receptors.[10] Again, Minnesota followed EPA's suggested approach.[11] In other words, while Minnesota was not required to, it followed EPA's own framework and did not rely on additional flexibilities to demonstrate that it had satisfied its Good Neighbor obligations.[12]

Minnesota also used the best information available at the time to determine its Good Neighbor obligations. Specifically, Minnesota used EPA's own modeling and modeling developed by the Lake Michigan Air Directors Consortium ("LADCO") to identify monitoring sites projected to have problems attaining or maintaining the 2015 ozone NAAQS in 2023.[13] It then projected the state's own contributions to those nonattainment and maintenance monitors using both sets of results.[14] Both EPA's and LADCO's modeling showed that Minnesota would contribute less than 1 percent of the NAAQS to all downwind receptors, with a highest receptor contribution from either model of 0.45 ppb.[15] Thus, following EPA's 4-factor framework, and using EPA's own modeling and proposed threshold, Minnesota demonstrated that it was not contributing significantly to, or interfering with maintenance of, the 2015 ozone NAAQS in any downwind state.

This alone would have been sufficient to satisfy Minnesota's Good Neighbor obligation. Minnesota also, however, included in its SIP submission a "step 3" analysis demonstrating that Minnesota emissions of ozone precursors had been reduced from 2002 through 2015 and would be further reduced by emission limitations and reductions required by other programs.[16] Under this step 3 analysis, Minnesota demonstrated that, even if the state were having more than an insignificant impact on downwind receptors (as EPA now asserts), Minnesota's existing glidepath of emissions reductions still supported a finding that no further emission control measures would

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[8] Transport Memo at A-2; Analysis of Contribution Thresholds for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards (Aug. 31 2018) ("Threshold Memo")

[9] 2018 SIP at 6.

[10] Transport Memo at A-2; Consideration for Identifying Maintenance Receptors for Use in Clean Air Act Section 110(a)(2)(D)(i)(I) Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards, https://www.epa.gov/sites/default/files/2018-10/documents/maintenance_receptors_flexibility_memo.pdf at 3 (October 19, 2018) ("Maintenance Memo")

[11] 2018 SIP at 5.

[12] Minnesota, of course, could have taken a different approach, and might have used some of these flexibilities, had EPA indicated during the statutory review period that it was considering disapproving prong 2 of Minnesota's SIP.

[13] 2018 SIP at 5-9.

[14] *Id.*

[15] *Id.* at 8-9.

[16] *Id.* at 9-12; *see also id.* at 13.

be needed to address this impact. EPA did not meet its obligation to approve or deny Minnesota's complete and approvable SIP within 12 months of submittal.

Approximately three years after EPA's deadline to approve the Minnesota SIP, EPA proposed to disapprove Minnesota's SIP on February 22, 2022, along with SIPs from 18 other states.[17] EPA did not identify a technical error in Minnesota's submission or any inconsistency with the Good Neighbor requirements, or even EPA's own framework. In fact, EPA recognized that "the modeling the MPCA used relied on the most recently available EPA modeling at the time the state submitted its SIP submittal."[18] Nonetheless, EPA proposed to reject Minnesota's SIP because EPA chose to rely "on the Agency's most recently available modeling, which uses a more recent base year and more up-to-date emissions inventories, to identify upwind contributions and 'linkages' to downwind air quality problems in 2023 using a threshold of 1 percent of the NAAQS." *Id.* Based on this data, EPA proposed to reject Minnesota's conclusion that it was not linked to a downwind receptor, and to find instead that Minnesota was linked to two maintenance monitors in Cook County, Illinois, one with a maximum contribution of 0.97 ppb and the other 0.79 ppb.[19]

On February 13, 2023, EPA published the SIP Disapproval. In its final rule, EPA approved Minnesota's SIP as to "prong 1" but disapproved Minnesota's SIP as to "prong 2."[20] Rather than use the emissions data and modeling available to Minnesota in 2018, or even emissions data and modeling available at the time of the proposed SIP disapproval, EPA made a number of additional updates to its emissions inventories and model design to construct a new 2016v3 emissions platform, which it used to generate new air quality modeling without seeking public comment to allow affected party input to help the agency assess the accuracy of the new information utilized in the modeling.[21] Minnesota was now no longer linked to two downwind receptors. It was now linked to only a single maintenance-only receptor, at a maximum contribution of 0.85 ppb for 2023.[22]

While EPA also conducted updated modeling for 2026, it did not release this information in the docket for the SIP Disapproval, stating it was "not applicable" and "not used in this final action."[23] EPA subsequently made these results available, however, on EPA's website for its Federal Implementation Plan ("FIP") for 23 states, including Minnesota.[24] Based on EPA's modeling for 2026, Minnesota is not linked to any downwind nonattainment or maintenance-only receptor. In fact, based on EPA's modeling, the sole maintenance-only receptor Minnesota was linked to in 2023 is in attainment by 2026, and Minnesota's largest contribution to any

[17] Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838, 9868 (February 22, 2022) ("Proposed Rule").
[18] Proposed Rule at 9867.
[19] *Id.* at 9868.
[20] *See* SIP Disapproval at 9357.
[21] *See id.* at 9339.
[22] *Id.* at 9357.
[23] *Id.* at 9344, n.49.
[24] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs

downwind nonattainment or maintenance-only receptor is just 0.32 ppb.[25] Notably, this modeling assumed no installation of additional pollution controls in Minnesota. The only emissions reductions included from Good Neighbor obligations were an annual reduction of 139 tons NOx from emissions control optimization at EGUs.[26]

II. Grounds for Reconsideration of the SIP Disapproval

Reconsideration is justified under either CAA § 307(d)(7)(B)[27] or Administrative Procedure Act ("APA") § 553(e) (5 U.S.C. § 553(e)).[28] Under CAA § 307(d), reconsideration is *required* "[i]f the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule."[29] Courts have found that an objection was "impractical to raise" "when the final rule was not a logical outgrowth of the proposed rule." *Alon Refining Krotz Springs, Inc. v. EPA*, 936 F.3d 628, 648 (D.C. Cir. 2019) (*per curiam*). In other words, when interested parties would not have "anticipated that the change was possible, and thus reasonably should have filed their comments on the subject during the notice-and-comment period." *CSX Transp., Inc. v. Surface Transp. Bd.*, 584 F.3d 1076, 1080 (D.C. Cir. 2009) (internal quotations omitted). An objection is of central relevance to the outcome of the rule if it "provides substantial support for the argument that the regulation should be revised." *Chesapeake Climate Action Network v. EPA*, 952 F.3d 310, 322 (D.C. Cir. 2020). Under the APA, EPA has "broad discretion to reconsider" its SIP Disapproval "at any time" Under the APA. *Clean Air Council v. Pruitt*, 862 F.3d 1, 8-9 (D.C. Cir. 2017).[30]

Three grounds support reconsideration under either standard. First, EPA's 2016v3 modeling did not have the benefit of Petitioners' or other public comments. As a result, it contains a significant overestimation of 2023 emissions for Minnesota. Second, EPA's 2016v3 modeling of the sole monitor supporting a potential linkage between Minnesota and Illinois is subject to significant bias which, if corrected for, results in the same receptor modeling attainment in 2023. Third, EPA's rejection of prong 2 of Minnesota's SIP was procedurally

[25] *See* Federal "Good Neighbor Plan" for the 2016 Ozone National Ambient Air Quality Standards, https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf, at 198 (pre-publication version).
[26] Compare *Id.* at 290, Table V.C.1-1; 291, Table V.C.1-2; and 452, Table VI.B.4.c-1.
[27] 42 U.S.C. § 76076(d)(7)(B).
[28] SIP disapprovals are not automatically subject to the exhaustion requirements of Clean Air Act § 307(d). 42 U.S.C. § 7607(d). This subsection lists 22 categories of agency action subject to the exhaustion requirement. SIP approval and disapproval, separate from issuance of a FIP, as occurred in the SIP Disapproval, is not addressed by any of these 22 categories.
[29] 42 U.S.C. § 7607(d)(7)(B).
[30] *See also Trujillo v. Gen. Elec. Co.*, 621 F.2d 1084, 1086 (10th Cir. 1980) ("Administrative agencies have an inherent authority to reconsider their own decisions, since the power to decide in the first instance carries with it the power to reconsider."); *United Gas Improvement Co. v. Callery Properties, Inc.*, 382 U.S. 223, 229 (1965) ("An agency, like a court, can undo what is wrongfully done by virtue of its order.")

improper because it was based entirely on results EPA obtained in 2023, well past the statutory deadline for Minnesota's SIP submission and EPA's decision approving or disapproving it.

A. Errors in EPA's New Emissions Data and Modeling, Which Were Not Subject to Notice and Comment, Support Reconsideration to Ensure EPA's Decision on Minnesota's SIP is Based on Valid and Accurate Information.

EPA "made a number of updates to [its] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval uses "this updated modeling to inform [EPA's] final action on [state] SIP submissions," including Minnesota's. *Id.*

The new emissions inventory and modeling platform are of central relevance to EPA's rule. EPA identifies the 2016v3 platform as designed "to inform [the agency's] final action on these SIP submissions." SIP Disapproval at 9339. For Minnesota, the 2016v3 modeling results are the sole record citation EPA provides for its finding that prong 2 of Minnesota's SIP was "ultimately inadequate." *Id.* at 9357.

While there have been errors in each of EPA's inventories at each stage of the regulatory process, these new errors in the emissions inventory arose only with the publication of the final SIP Disapproval. Under both the APA and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment on the evidence on which EPA intends to rely for its final rules.[31] EPA's emissions inventory and modeling design changes were not made publicly available until EPA published the SIP Disapproval and several supporting documents on the same day. As a result, the public, including Petitioners, did not have the opportunity to review EPA's data and correct errors before then.

In the limited time Petitioners have had to review the 2016v3 data, we have identified significant errors in EPA's estimate of NOx emissions for 2023. As an example, EPA added 2,822 tons of NOx for Northshore Mining Co. – Silver Bay power. These boilers have been idled since October 2019 and are expected to have zero emissions in 2023. EPA itself recognizes that zero emissions are expected at this facility in both its OTP Policy Analysis, Appendix A and in its Unit-Level Allocations and Underlying Data for the Final Rule (both available at https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs). Yet EPA made no adjustment to its 2016v3 data, resulting in a significant overestimate of 2023 emissions from Minnesota used by EPA to justify disapproval of the Minnesota SIP. If EPA defends including 2,822 tons of NOx emissions for Silver Bay Power in the baseline actual emissions used to model Minnesota's downwind impact in 2023, then Minnesota's state allowance budget should be

[31] *See Small Ref. Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 540 (D.C. Cir. 1983) (adding evidence on which EPA relies after the close of the comment period would be "highly improper"); *see also Sierra Club v. Costle*, 657 F.2d 298, 400 (D.C. Cir. 1981) ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."); *see also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982) (finding EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations).

increased to reflect those emissions and Silver Bay Power should receive proportional allowance allocations for the 2023 CSAPR ozone season trading program and beyond. To do otherwise would be internally inconsistent, which is an indication of arbitrary rulemaking.

For Minnesota, EPA's most recent modeling identified a single impacted maintenance monitor in 2023, at which Minnesota's maximum impact was 0.85 ppb. EPA's latest modeling projects this same receptor will be in attainment by 2026 with no reductions from Minnesota other than already "on the books" rules and regulations.[32] In other words, EPA's 2026 modeling confirms Minnesota's 2018 SIP conclusion that "the limits and controls that Minnesota already has in place across the state are sufficient to make it reasonably certain that Minnesota will not significantly contribute to nonattainment or interfere with maintenance in any other state" and that "no further controls or emissions limits are required to fulfill [Minnesota's] responsibilities under the interstate transport provisions for the 2015 ozone NAAQS under prongs 1 and 2 of Section 110(a)(2)(D)(i)(I)."[33]

Given the above considerations, EPA should grant reconsideration to reassess Minnesota's 2018 SIP in light of its own modeling showing that no further emission reductions are needed for Minnesota to satisfy its prong 2 good neighbor obligations.

B. The Sole Monitor that Links Minnesota Models in Attainment for 2023 When Bias is Removed.

Minnesota's only link to a downwind state receptor is the Alsip/Village Garage monitor located in Cook County, Illinois (170310001). This monitor is located near the southern shore of Lake Michigan at a land-water interface with complex meteorology**.** This monitor is currently measuring attainment with the 2015 ozone NAAQS using the 2021 4th highest daily maximum value (68 ppb). However, EPA's air quality modeling predicts that this monitor is at risk of violating the ozone NAAQS and, therefore, designates it as a maintenance-only receptor. Upwind states that interfere with this monitor's maintenance of the ozone NAAQS are linked through prong 2**.** However, if a corrected model predicts the monitor's maximum 2023 design value will attain the 2015 ozone NAAQS, this monitor falls out of the analysis at Step 1 and, since no other monitor links to Minnesota, EPA will have no basis for disapproval of prong 2 of Minnesota's SIP.

In the attached analysis, Alpine Geophysics demonstrates that the Cook County monitor models attainment for the 2015 ozone NAAQS in 2023. Alpine Geophysics evaluated this Cook County monitor and concluded that its location at a land-water interface at the southern shore of Lake Michigan presents highly complex meteorological conditions and ozone photochemistry that complicate the air quality model's ability to replicate ozone concentrations reliably. Of note,

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[32] *See* Air Quality Modeling Final Rule Technical Support Document, https://www.epa.gov/system/files/documents/2023-03/AQ%20Modeling%20Final%20Rule%20TSD.pdf at 17, Table 3-5 (showing Monitor 170310001 no longer listed as a monitor-only receptor in the 2026 base case).

[33] 2018 SIP at 13.

EPA's application of a 12 km grid resolution in such areas is contrary to EPA's own guidance.[34] Alpine Geophysics reviewed EPA's day-specific model performance for the estimation of ozone concentrations on days EPA used to calculate future year design values and found significant bias in the majority of modeled day values used to designate this monitor site as a maintenance-only receptor. When Alpine Geophysics adjusted for this bias by using daily concentration values within acceptable normalized bias boundaries (+/- 15%), the updated list of top ten days used to designate the Cook County monitor resulted in both its average and maximum design values to be calculated in attainment with the 2015 ozone NAAQS.

When one attaining monitor modeled as a maintenance-only receptor is the sole basis for a state's linkage, a refined level of analysis is particularly important when predicting future design values and significant contribution. When that monitor is in a highly complex land-water interface area, it is not surprising for refined analysis to show significant bias. In its FIP rulemaking, EPA looked at this impact, but evaluated only one of ten Cook County monitors.[35] In doing so, EPA evaluated the only monitor out of the ten where EPA's performance-based recalculation resulted in a higher design value. As a result, EPA's sensitivity analysis materially understates the significance of the bias impact on the Alsip/Village Garage monitor and this issue remains central to EPA's evaluation of Minnesota's 2018 SIP.

Petitioners also had no ability to evaluate the bias in EPA's 2016v3 modeling of the Alsip/Village Garage monitor prior to EPA's release of its model and supporting data. As a result, this information arose after the close of the public comment period and within the time for judicial review.

Since Petitioners have identified significant bias in the sole receptor on which EPA relies to find a link to Minnesota and reject Minnesota's 2018 SIP, reconsideration is appropriate to evaluate the new information and analysis provided. When reasonably adjusting for the bias in EPA's 2016v3 modeling of that receptor, EPA will be in a position to confirm that Minnesota accurately concluded in 2018 that there are no "potential nonattainment or maintenance receptors significantly impacted by ozone transport from Minnesota in 2023" and that "[t]herefore, Minnesota does not have a responsibility to identify or implement any further controls or emissions limits to reduce downwind ozone contribution."[36]

C. Minnesota's SIP Should Have Been Approved Based on the Data Available at the Statutory Deadlines for Submission or Review.

The Clean Air Act sets out a detailed process for EPA's review of SIPs in CAA § 110(k). 42 U.S.C. § 7410(k). For timely submitted plans that have been deemed complete, like Minnesota's,

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[34] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$ and Regional Haze, https://www.epa.gov/sites/default/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf (Nov. 29, 2018).

[35] *See* Federal "Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards Response to Public Comments on Proposed Rule, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf at 196.

[36] 2018 SIP at 9.

EPA has twelve months to act on a plan submission. 42 U.S.C. § 7410(k)(2). For a plan that meets the requirements of the Clean Air Act, "the Administrator shall approve such submittal as a whole." *Id.* at (k)(3). If a portion of the plan revision meets all the applicable requirements, EPA "may approve the plan revision in part and disapprove the plan revision in part" but "[t]he plan revision shall not be treated as meeting the requirements of [the Clean Air Act] until the Administrator approves the entire plan revision as complying with the applicable requirements of [the Clean Air Act]." *Id.* In other words, while EPA has discretion to partially approve a SIP submittal that does not meet all requirements of the Clean Air Act, if a submission meets all requirements of the Act, EPA does not have discretion. It must approve the SIP. *See also Utah Physicians for a Healthy Env't v. Kennecott Utah Copper, LLC*, 191 F. Supp. 3d 1287, 1290 (D. Utah 2016) ("If a SIP satisfies the applicable requirements, EPA must approve it.").

In 2018, Minnesota submitted a timely and approvable SIP. As EPA acknowledges in the SIP Disapproval, Minnesota "was not projected to be linked to any receptor in 2023 in the EPA's 2011-based modeling."[37] Petitioners retained Alpine Geophysics to reanalyze Minnesota's SIP submission considering the best evidence available both at the time of Minnesota's SIP submission and at the time of EPA's statutory obligation to approve or disapprove Minnesota's SIP. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota's SIP submission: (1) had no material errors; (2) relied on the best science (including emissions data and modeling) available at the time; (3) fully complied with the CAA's requirements and EPA's guidance; and (4) would have been approved had EPA not incorporated information unavailable during the statutory review period. As a result, pursuant to 42 U.S.C. § 7410(k)(2) and (k)(3), by April 1, 2020, EPA had a non-discretionary duty to approve Minnesota's SIP. While EPA missed its statutory deadline, this did not relieve EPA of its duty to approve Minnesota's SIP.

While EPA now finds that "in light of more recent air quality analysis," Minnesota is linked to a single maintenance monitor in Illinois, this is based on information that did not exist at the time of Minnesota's SIP submission nor when EPA had a statutory obligation to approve the SIP. This was also not EPA's first use of untimely information to assess Minnesota's SIP. In 2022, EPA proposed to disapprove Minnesota's SIP "[s]ince new modeling ha[d] been performed by EPA with updated emission data," that EPA proposed "to primarily rely on … to identify nonattainment and maintenance receptors in 2023." Proposed Rule at 9867. As EPA acknowledged at the time, this was "a different method for projecting emissions" than what had been available to Minnesota for it to develop its SIP submittal. *Id.* EPA's repeated changes in emissions inventory and modeling platform after the deadline for SIP submissions and after Minnesota's SIP was deemed complete by EPA effectively moved the goalpost for Minnesota's SIP, undercutting the State of Minnesota's ability to identify the requirements EPA would apply to determine an approvable SIP.

The impact was significant. Minnesota's modeled impact went from contributing "below 1 percent of the NAAQS to receptors in 2023" to contributing "greater than 1 percent of the standards to two maintenance-only receptors in Illinois"[38] in the 2022 proposed SIP Disapproval

[37] SIP Disapproval at 9357.
[38] *Id.* at 9867-68.

to now being linked to one maintenance-only receptor in the 2023 SIP Disapproval (assuming no further adjustment for bias or data inaccuracies)). Notably, even using EPA's new data and modeling, Minnesota would still have had no linkage to a downwind maintenance receptor if EPA had not also moved the maximum threshold it indicated it would consider acceptable from 1 ppb to 1% (0.70 ppb).[39] As the D.C. Circuit has held, it is arbitrary and capricious to give states a "constantly moving target," *New York v. EPA*, 964 F.3d 1214, 1224 (D.C. Cir. 2020), let alone two. The language and structure of the Clean Air Act clearly give Minnesota and Petitioners the right to address this new data in the first instance in a SIP amendment, and not in a challenge to a SIP disapproval, as EPA now requires.

Notably, if EPA had followed the CAA procedures, it could have appropriately considered the new information it has developed since 2020, including the 2016v3 modeling it has introduced with the 2023 SIP Disapproval. But EPA cannot rely on its almost three year delay to circumvent the process and procedural protections set forth in the Clean Air Act. Rather, EPA was required to act on the SIP Minnesota submitted. If, after approval, EPA finds that a timely, complete and approved SIP nonetheless is "substantially inadequate … to mitigate adequately the interstate pollutant transport" or otherwise comply with the requirements of the Clean Air Act, "the Administrator shall require the State to revise the plan as necessary to correct such inadequacies." *Id.* at (k)(5). EPA also cannot simply disapprove the state's plan pending a new state submission that incorporated EPA's newly developed information, as the SIP Disapproval effectively does. In the event EPA finds a SIP Call is justified, EPA must first "notify the State of the inadequacies, and may establish reasonable deadlines (not to exceed 18 months after the date of such notice) for the submission of such plan revisions." *Id.* Further, "[s]uch findings and notice shall be public." *Id.* These procedural protections are an important component of the cooperative federalism embodied in the Clean Air Act. As courts have held, "[t]he Clean Air Act is an experiment in federalism, and the EPA may not run roughshod over the procedural prerogatives that the Act has reserved to the states, especially when … the agency is overriding state policy. *Bethlehem Steel Corp. v. Gorsuch*, 742 F.2d 1028, 1036–37 (7th Cir. 1984).

Multiple commenters, including the Minnesota Pollution Control Agency, have raised similar concerns arising from EPA's initial proposal to use 2016v2 modeling to disapprove state SIPs.[40] EPA has attempted to respond to those comments in the RTC, but in doing so, has not addressed the fundamental issue that EPA cannot disapprove a SIP that is approvable based on the information existing at the time that submittals are due, or even at the time EPA's SIP review was statutorily due, and cannot circumvent Minnesota's right to address new data in a SIP amendment, before EPA uses it to disapprove an otherwise approvable SIP. 42 U.S.C. §§ 7410(k)(3) and (5).

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[39] Minnesota did not rely on the 1 ppb threshold for its SIP submission, but as EPA acknowledged, "[t]he 2018 modeling indicated the state was not projected to contribute above one 1 percent of the NAAQS to a projected downwind nonattainment or maintenance receptor. Therefore, the state may not have considered analyzing the reasonableness and appropriateness of a 1 ppb threshold at Step 2 of the 4-step Step interstate transport framework per the August 2018 memorandum." Proposed Rule at 9867.

[40] *See* RTC at 42-59.

EPA asserts in the SIP Disapproval that its use of new modeling and data did not move the goal post for states because EPA "did not evaluate states' SIP submissions based solely on the 2016v2 emissions platform (or the 2016v3 platform…)" but rather "evaluated the SIP submissions based on the merits of the arguments put forward in each SIP submission." SIP Disapproval at 9366. For Minnesota, however, EPA cites no basis or analysis for its SIP Disapproval other than the 2016v3 modeling results. Having relied on no other information to disapprove Minnesota's SIP, EPA cannot simply assert it had an additional basis with no additional substantiation. As the D.C. Circuit has noted, EPA cannot support its decision on only a "Delphic explanation of [Minnesota's] purported failure to carry its burden of proof." *New York*, 964 F.3d at 1224.

EPA also maintains that data and modeling it developed for the Proposed Rule in 2022, and now additional data and modeling it developed for the SIP Disapproval in 2023, supports a finding that Minnesota's SIP submission is "ultimately inadequate." SIP Disapproval at 9357. But even if this were the case, it does not give EPA a right to disapprove Minnesota's 2018 SIP. For data arising after EPA's statutory deadline to approve Minnesota's SIP, EPA could no longer rely on its obligation to use the "best information available." SIP Disapproval at 9366. Interpreting the Clean Air Act otherwise would not do justice to the cooperative federalism framework Congress established in CAA § 110, and would deprive states of important procedural protections allowing them to control and direct in the first instance, the implementation of the NAAQS within their borders.

The SIP Disapproval misapplies the D.C. Circuit's reasoning in *Wisconsin*, 903 F.3d at 322, when it asserts the SIP submission deadline is "'procedural'" and that to limit EPA's decision to information available at the time of the SIP submission or EPA's statutory review deadline would elevate it above requirements "'central to the regulatory scheme.'" SIP Disapproval at 9366 (quoting *Wisconsin*, 903 F.3d at 322. Neither *Wisconsin*, nor the case on which it relies, *Sierra Club v. EPA*, 294 F.3d 155 (D.C. Cir. 2002), addressed the issue presented here. In *Wisconsin*, the court was responding to an argument that EPA should have selected 2011 as its analytic year even though that year had already passed. In *Sierra Club*, the court was responding to a contention that EPA's ability to extend a SIP submittal deadline should support its authority to extend attainment deadlines. Here, EPA argues for an exception that would swallow the rule. If EPA could simply withhold ruling on a SIP until the State's information had become stale, and then disapprove the SIP and issue a FIP based on the "best available information," the cooperative federalism structure of the NAAQS would be an empty shell.

This is also not a situation like that which arose in *EME Homer City Generation, L.P. v. EPA,* 795 F.3d 118 (D.C. Cir. 2015). There, EPA had approved state SIPs in reliance on the Clean Air Interstate Rule ("CAIR"), which was subsequently found to have "more than several fatal flaws" by the D.C. Circuit. *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C.Cir.2008) (*per curiam*). In addressing whether this ruling allowed EPA to "correct" its earlier SIP approvals under 42 U.S.C. § 7410(k)(6), the D.C. Circuit found EPA could do so, but only due to the unique circumstances of that case. *EME Homer City Generation*, 795 F.3d at 135 n.12 ("Our conclusion on Subsection 7410(k)(6) is limited to the unusual circumstances here, in which a federal court says that EPA lacked statutory authority at the time to approve a SIP."). Notably, the D.C. Circuit

did not decide whether EPA could rely on Clean Air Act §110(k)(6) to disapprove an approved SIP "in any other circumstances," and stated that its holding in particular "should not be read to diminish the scope or force of Subsection 7410(k)(5), which provides that whenever 'the Administrator finds that the applicable implementation plan for any area is substantially inadequate ... the Administrator shall require the State to revise the plan as necessary to correct such inadequacies.'" *Id.* (quoting 42 U.S.C. § 7410(k)(5)).

While in *EME Homer,* EPA had already approved several state SIPs, and in this rulemaking EPA has not yet approved Minnesota's SIP, this is a distinction without a difference. Minnesota submitted its SIP on October 1, 2018. It was deemed complete April 1, 2019.[41] EPA's period for review therefore ended April 1, 2020. As described in the Proposed Rule, Minnesota's SIP submission complied with the Clean Air Act and EPA's guidance for developing an interstate transport SIP for the 2015 ozone NAAQS. 87 Fed. Reg. at 9848-49. As detailed in the attached report, Alpine Geophysics' review confirms that Minnesota timely submitted an approvable SIP. By April 1, 2020, EPA had a statutory duty to approve Minnesota's SIP.

EPA's reliance on its 2016v3 modeling platform (which was not available to the public or interested parties) to reject the conclusions Minnesota reached based on the information that was available to all parties at the time is clearly of central relevance. Had EPA acted by its statutory deadline, Minnesota would have an approved SIP today. Further, while Petitioners have previously commented on the approvability of Minnesota's SIP, the basis for EPA's partial SIP Disapproval for Minnesota, including its decision to rely on its newer 2016v3 modeling platform, was not made public until the final rule. These grounds therefore arose after the close of the public comment period but before the time for judicial review. Reconsideration is therefore appropriate to address this procedural anomaly for Minnesota.

On reconsideration EPA should approve Minnesota's 2018 SIP based on the information that was available to EPA for its statutory review. The agency may then reassess whether, based on the information available today, including the above data and bias corrections, Minnesota's SIP remains sufficient to comply with prong 2 of the state's Good Neighbor obligations. For the reasons explained herein, EPA should find that the 2018 SIP was and is adequate to comply with prong 2.

III. Grounds for Stay of the SIP Disapproval

EPA has authority to stay the SIP Disapproval both pending reconsideration and pending judicial review. First, if the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration can be granted for three months. Second, EPA has authority under the APA to stay the SIP Disapproval pending judicial review.

[41] *See* https://www3.epa.gov/airquality/urbanair/sipstatus/reports/mn_infrabypoll.html

A. A Stay Under CAA § 307(d)(7) is Appropriate.

The Clean Air Act provides that, if EPA grants reconsideration of a rule, "[t]he effectiveness of the rule may be stayed during such reconsideration…by the Administrator or the court for a period not to exceed three months." 42 U.S.C. § 7607(d)(7)(B). If the SIP Disapproval is subject to CAA § 307(d), a stay pending reconsideration is justified here.

EPA issued a final rule based primarily on emissions data and modeling that it did not make publicly available before issuance of the final rule. Even upon publication, EPA's release of data was partial and inadequate to reconstruct the modeling that EPA used for its final determinations. Obtaining the data and checking its accuracy has taken several weeks. It would take many more weeks to rerun EPA's modeling to confirm that the results support reversal of EPA's disapproval of prong 2 of Minnesota's SIP. It will likely take a similar amount of time to evaluate the evidence of bias Petitioners are submitting to confirm that it too, supports approval of Minnesota's SIP.

A stay will also not unduly impact downwind states. Minnesota is not modeled to interfere with attainment for any downwind state. Under EPA's most recent modeling, Minnesota is linked only to a single maintenance-only receptor, the most recent monitored design value of the monitor at this location was in attainment, and EPA's modeling for 2026 shows the receptor will model attainment as well with only minimal reductions from Minnesota. As EPA has itself emphasized, the SIP Disapproval does not require any action from the states.[42]

While a stay of the effective date of the SIP Disapproval for Minnesota would also prevent EPA from applying its FIP to Minnesota at the start of the upcoming ozone trading season, which is scheduled to start May 1, 2023, this is not likely to be relevant. In a recent filing, EPA has stated that the FIP is not likely to be effective until "late June to early July."[43] If EPA timely takes action on this reconsideration, this is well within the time EPA would need to conduct reconsideration. Further, while EPA has interpreted the CAA to require it "to address good neighbor obligations as expeditiously as practicable and no later than the next attainment date," RTC at 445, granting a stay of Minnesota's SIP denial pending reconsideration will not interfere with that goal. Minnesota is modeled to impact only a single maintenance-only monitor. As the D.C. Circuit has recognized, this 'may be a valid reason" to postpone addressing emission reductions until even after the next attainment date. *North Carolina v. EPA*, 531 F.3d 896, 912 (D.C. Cir. 2008). A reasonable stay to address reconsideration falls well within EPA's discretion.

B. EPA Should Stay the Effective Date of the SIP Disapproval Pending Judicial Review.

EPA can consider a stay of the entire SIP Disapproval for all affected states. Under the APA, EPA may stay the effective date of the SIP Disapproval pending judicial review when "justice

[42] *See, e.g.*, 2015 Ozone NAAQS Interstate Transport SIP Disapproval – Response to Comments ("RTC") at 466.
[43] Respondents' Consolidated Response in Opposition to the Motions for Stay of the Final Rule, *Texas v. EPA*, Case No. 23-60069, Doc. 109, at 12 (5th Cir. Filed March 27, 2023).

so requires." 5 U.S.C. § 705. Several Petitioners are filing a petition for judicial review of EPA's partial disapproval of Minnesota's SIP contemporaneously with this petition for reconsideration and stay. Multiple other petitions have already been filed for judicial review, including petitions by Arkansas, Kentucky, Oklahoma, Texas, Utah, and Wyoming. More are likely. These cases are already spread across four circuits, and additional litigation may expand the number of courts further.

The effective date of the SIP Disapproval is March 15, 2023. This effective date is significant for both legal and practical reasons. Legally, it will force EPA to promulgate a FIP within two years (though in this case EPA has already finalized its FIP). 42 U.S.C. § 7410(c)(1). States will also be required to prepare SIP revisions if they are interested in addressing the errors in EPA's analysis. Further, the significant legal flaws in EPA's SIP Disapproval discussed above, coupled with the technical and legal concerns it raises, make it likely that judicial review will result in a remand if not vacatur of the current SIP Disapproval. As a result, to avoid the unnecessary expenditure of EPA resources on a FIP, state resources on SIP revisions, and the resources of the public and regulatory industries in addressing a FIP that is likely to not be required, justice requires that the SIP Disapproval be stayed pending judicial review.

Further, while EPA is not bound to apply the same four-factor analysis used by courts for granting a judicial stay pending review, these factors indicate support for EPA in granting a stay of the SIP Disapproval. Under this standard, the considerations for a stay are:

(1) whether the stay applicant has made a strong showing that he is likely to succeed on the merits;

(2) whether the applicant will be irreparably injured absent a stay;

(3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and

(4) where the public interest lies.

Nken v. Holder, 556 U.S. 418, 434, 129 S.Ct. 1749, 173 L.Ed.2d 550 (2009) (citation omitted). These "four considerations are factors to be balanced and not prerequisites to be met." *State of Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n*, 812 F.2d 288, 290 (6th Cir. 1987).

1. Petitioners Have Made a Strong Showing They Are Likely to Succeed on the Merits

There is no fixed probability of success the agency must find in applying these considerations. "Ordinarily the party seeking a stay must show a strong or substantial likelihood of success. However, at a minimum the movant must show 'serious questions going to the merits and irreparable harm which decidedly outweighs any potential harm to the defendant if a [stay] is issued.'" *Id. (quoting In re DeLorean Motor Company*, 755 F.2d 1223, 1229 (6th Cir.1985)).

As discussed above, the SIP Disapproval has substantive and procedural flaws, each of which individually, and more so when combined, demonstrate "a high probability of success on the merits." *Ohio ex rel. Celebrezze v. Nuclear Regul. Comm'n.*, 812 F.2d 288, 290 (6th Cir.1987). Substantively, EPA's partial SIP Disapproval for Minnesota was based on an incorrect set of emissions data and biased modeling results that, when adjusted, support Minnesota's original conclusion that the state is not linked to downwind nonattainment or interference with maintenance and, even if linked, does not need to impose additional emission reductions to satisfy its Good Neighbor obligations. Procedurally, EPA did not follow the process required by the Clean Air Act for reviewing and approving Minnesota's SIP. In doing so, EPA deprived the State and Petitioners of the ability to address EPA's concerns in a SIP Call process.

Other flaws in the SIP Disapproval also strongly support a showing of likely success on the merits in a judicial challenge. In particular, we call to the agency's attention: (a) EPA's impermissible reliance on new data to disapprove prong 2 of Minnesota's SIP without providing adequate notice and an opportunity for public comment; and (b) the SIP Disapproval's subversion of the well-established and vital cooperative federalism underlying the entire Clean Air Act and in particular, the NAAQS.

a. *EPA Cannot Base its SIP Disapproval on Information that was Not Subject to Adequate Notice and Public Comment*

Under both the Administrative Procedure Act ("APA") and the CAA, EPA's rulemaking process requires adequate public notice and an opportunity to comment. *Small Ref.*, 705 F.2d at 547. This includes providing the public with the evidence on which EPA intends to rely. *Id.* at 540. Adding evidence on which EPA relies after the close of the comment period is "highly improper." *Id.* at 540; *see also Sierra Club*, 657 F.2d at 400 ("If … documents of central importance upon which EPA intended to rely had been entered on the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."). Even reconsideration cannot cure an inadequate opportunity for notice and comment. *U. S. Steel v. EPA*, 595 F.2d 207, 214 (5th Cir. 1979) ("Permitting the submission of views after the effective date is no substitute for the right of interested persons to make their views known to the agency in time to influence the rulemaking process in a meaningful way.") (Internal quotations omitted).

In the SIP Disapproval, EPA "made a number of updates to [it's] inventories and model design to construct a 2016v3 emissions platform which was used to update [EPA's] air quality modeling." SIP Disapproval at 9339. The SIP Disapproval used "this updated modeling to inform [EPA's] final action on [Minnesota's] SIP submissions." *Id.* The details of these emissions inventory and modeling design changes were first described to the public in the SIP Disapproval and associated documents made publicly available the same day.[44] Even then, EPA did not make public its 2026 modeling results, reserving these for finalization of the FIP several weeks later.

[44] Even then, the supporting data and modeling platform were not made electronically available and needed to be requested by the public, which added several more weeks to gain access.

This data and modeling were clearly of central importance to EPA's disapproval of prong 2 of Minnesota's SIP. In fact, they are the sole basis for EPA's disapproval. *See* SIP disapproval at 9357 (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"); *see also id*. (disapproving prong 2 of Minnesota's SIP because "[i]n the 2016v3 modeling, Minnesota is projected to be linked above 1 percent of the NAAQS to one maintenance-only receptor"). As a result, EPA was required to provide the public advance notice of its new data and an opportunity for meaningful public comment.

EPA's publication of its revised emissions inventory and modeling the day of the SIP Disapproval did not satisfy this requirement. In *Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C. Cir. 1982), the D.C. Circuit found EPA had not provided adequate opportunity for public comment on economic modeling placed in the docket only one week before promulgation of its final regulations. Here, EPA did not make its new emissions data and modeling publicly available until the *day* it published its final SIP Disapproval.

It is not enough to say that Petitioners had the opportunity to comment on EPA's previous version of the emissions data and modeling, or that EPA's latest data simply "incorporates comments generated during the public comment period." SIP Disapproval at 9366. As the D.C. Circuit stated in *Chesapeake*, 952 F.3d at 320, it would be an "unreasonable burden on commenters not only to identify errors in a proposed rule but also to contemplate why every theoretical course of correction the agency might pursue would be inappropriate or incorrect." The new data and modeling on which EPA relies for the SIP Disapproval differs significantly from that which was in the public record. Based on EPA's own summary of the data, Minnesota's largest contribution to a downwind maintenance receptor changed from 0.97 ppb to 0.85 ppb based on EPA's changes. *Compare* Proposed Rule at 9868 *with* SIP Disapproval at 9354. Since EPA's own adopted significant contribution threshold in the SIP Disapproval is 0.7 ppb, a change of 0.12 ppb is clearly significant.[45]

Under both the CAA and the APA, EPA was required to provide notice and an opportunity for public comment on its 2016v3 data. There is no question that EPA provided no notice or opportunity for comment. As a result, there is a high likelihood that Petitioners would be likely to prevail on the merits of a judicial challenge. This strongly supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

b. *EPA Undermined State Primacy by Disapproving Minnesota's SIP Despite its Adherence to the Requirements of the Clean Air Act.*

As EPA acknowledges, "[t]he CAA establishes a framework for state-Federal partnership to implement the NAAQS based on 'cooperative federalism.'" SIP Disapproval at 9367. Under this model, "the Federal Government establishes broad standards or goals, states are given the

[45] EPA's 2016v3 modeling did not just result in significant changes to EPA's assessment of Minnesota's potential impact on downwind states. Six states (Arizona, Iowa, Kansas, New Mexico, Tennessee, and Wyoming) had their status as linked states change entirely. *See* Air Quality Modeling Technical Support Document 2015 Ozone NAAQS SIP Disapproval Final Action, https://www.regulations.gov/document/EPA-HQ-OAR-2021-0663-0017 at 24.

opportunity to determine how they wish to achieve those goals, and if states choose not to or fail to adequately implement programs to achieve those goals, a Federal agency is empowered to directly regulate to achieve the necessary ends." *Id.* Thus, "states have the obligation and opportunity in the first instance to develop an implementation plan to achieve the NAAQS under CAA section 110" and "EPA will approve SIP submissions under CAA section 110 that fully satisfy the requirements of the CAA." *Id.* As the Supreme Court has held: "[e]ach State is given wide discretion in formulating its plan, and the Act provides that the Administrator 'shall approve' the proposed plan if it has been adopted after public notice and hearing and if it meets [the CAA's] criteria." *Union Elec. Co. v. EPA*, 427 U.S. 246, 250 (1976) (*quoting* 42 U.S.C. § 7410(a)(2)).

EPA departed from this framework when it proposed a SIP disapproval based, not on any inaccuracy in Minnesota's evaluation of the data, but on EPA's preference for a different modeling platform and emissions inventory. EPA does not have the authority to condition SIP approval on the state's adoption of EPA's preferred approach, or to supplant Minnesota' interpretation of how best to achieve the goals of the CAA, as long as Minnesota complies with the requirements of the CAA.

EPA's position is predicated on an incorrect summary of its role in the SIP review process and the relevant case law. First, EPA's role is not "secondary" only in that "it occurs second in time." RTC at 425 (internal quotations omitted). EPA relies on *EPA v. EME Homer City Generation*, LP, 572 U.S. 489 (2014) for this proposition, but the case does not support EPA's position. It must be remembered that *EME Homer* involved EPA's authority to promulgate a FIP after EPA had already disapproved SIPs.[46] As a result, the Court did not address EPA's statutory duty to approve a timely and complete SIP submission, which is the issue here. The Court's "interpretations of CAA section 110(a)(2)(D)(i)(I)" on which EPA relies must be read in this light. RTC at 426. The Court upheld interpretive choices EPA made when issuing a FIP. The Court did not say EPA could delay approval until new information became available that supported its disapproval of the SIP.

Second, EPA is wrong to imply that *EME Homer* undermines the long line of cases setting out EPA's secondary (in substance, not just in time) role in developing plans to implement the NAAQS. In fact, the Supreme Court continues to cite these cases for their interpretation of EPA's role. *See West Virginia v. EPA*, 213 L. Ed. 2d 896, 142 S. Ct. 2587, 2600 (2022) ("EPA … does not choose which sources must reduce their pollution and by how much to meet the ambient pollution target. Instead, Section 110 of the Act leaves that task in the first instance to the States, requiring each 'to submit to [EPA] a plan designed to implement and maintain such standards

[46] *See EME Homer*, 572 U.S. at 507 ("The gravamen of the State respondents' challenge ***is not that EPA's disapproval of any particular SIP was erroneous***. Rather, respondents urge that, notwithstanding these disapprovals, the Agency was obliged to grant an upwind State a second opportunity to promulgate adequate SIPs once EPA set the State's emission budget. ***This claim does not depend on the validity of the prior SIP disapprovals***. Even assuming the legitimacy of those disapprovals, the question remains whether EPA was required to do more than disapprove a SIP, as the State respondents urge, to trigger the Agency's statutory authority to issue a FIP.") (emphasis added).

within its boundaries.'") (*quoting Train v. Natural Resources Defense Council, Inc.*, 421 U.S. 60, 65 (1975)).

The SIP Disapproval and RTC makes clear that EPA's disapproval of prong 2 of Minnesota's SIP was not based on a determination that Minnesota's SIP failed to meet the statutory requirements of CAA, but because EPA wanted to apply "a consistent set of policy judgments across all states for purposes of evaluating interstate transport obligations and the approvability of interstate transport SIP submissions for the 2015 ozone NAAQS under CAA section 110(a)(2)(D)(i)(I)." SIP Disapproval at 9339; *see also id.* at 9340 ("Effective policy solutions to the problem of interstate ozone transport going back to the NOx SIP Call have necessitated the application of a uniform framework of policy judgments to ensure an 'efficient and equitable' approach.") (quoting *EME Homer*, 572 U.S. at 519); RTC at 425-426. This was error. EPA's assessment of a SIP is to be based on whether the SIP compiles with the requirements of the CAA, not on EPA's policy preferences or desire for efficiency. Only after a state fails to comply with its statutory requirements can EPA impose what it believes best to achieve the substantive objective of the Act.

Because EPA's SIP Disapproval is based on improper factors that undermine the core cooperative federalism embodied in CAA § 110, Petitioners are likely to prevail on the merits of a judicial challenge. This further supports EPA issuing a stay of the effective date of the SIP Disapproval pending judicial review.

2. Petitioners Will Suffer Irreparable Harm from a Denial of Stay.

Relevant factors for evaluating the harm which will occur include: (1) the substantiality of the injury alleged; (2) the likelihood of its occurrence; and (3) the adequacy of the proof provided. In evaluating the harm which will occur both if the stay is issued and if it is not, the court must look to three factors: the substantiality of the injury alleged, the likelihood of its occurrence, and the adequacy of the proof provided. *Ohio ex re. Celebrezze*, 812 F.2d at 290 (*citing Cuomo v. United States Nuclear Regulatory Commission*, 772 F.2d 972, 974 (D.C.Cir.1985)).

The SIP Disapproval poses substantial and imminent injuries to Petitioners. As discussed in Section II above, the data which EPA should have used to evaluate Minnesota's SIP (see Section II.C), the best available data today, when flaws are addressed (see Sections II.A and B), and even the most likely future data (see Section II.D) strongly support a finding that Minnesota is not significantly contributing to nonattainment or interfering with maintenance of the 2015 ozone NAAQS in any state. EPA's SIP denial is predicated on the erroneous conclusion that there *is* interference with maintenance. This places the entire State of Minnesota in an erroneous state of non-compliance with the Good Neighbor requirement of the Clean Air Act.

EPA's SIP Disapproval also forces EPA to promulgate emission reductions through a FIP. 42 U.S.C. § 7410(c). EPA has already finalized just such a rulemaking. This leaves no time for reconsideration or judicial review to run its course before Petitioners are injured by the FIP, let alone time for Minnesota to remedy EPA's issues with the submitted SIP. Petitioners submitted detailed comments on the FIP identifying numerous substantial injuries from EPA's promulgation

of its Proposed FIP that are likely to occur, and supported by substantial evidence, including detailed technical reports.[47] While EPA made substantial modification to the FIP in response to comments, which Petitioners appreciate reflects considerable work on the Agency's part following the public comment period and has addressed many significant issues with the proposed FIP, the final FIP nonetheless includes significant obligations for Petitioners' electric generating units ("EGUs"), starting in the current 2023 ozone trading season (which begins this year). Even Petitioners without EGUs are substantial consumers of electricity, meaning that they will likely bear much of the burden of the higher costs needlessly imposed on Minnesota power producers because of the FIP. Further, while the Proposed FIP is a separate rulemaking, EPA has itself identified the SIP Disapproval as both a necessary step in issuance of a final FIP[48] and the stay of a SIP disapproval that is the basis for a FIP is an appropriate remedy for injuries arising from the FIP itself. *See EME Homer City Generation, L.P. v. EPA*, 696 F.3d 7, 44 n.6 (D.C. Cir. 2012) (Rogers, J., dissenting), *rev'd on other grounds,* 572 U.S. 489 (2014) ("If [states] wish to avoid enforcement of the Transport Rule FIPs because they contend EPA's SIP disapprovals were in error, the proper course is to seek a stay of EPA's disapprovals in their pending cases; if granted, a stay would eliminate the basis upon which EPA may impose FIPs on those States.") (citing 42 U.S.C. § 7410(c)(1)(B)).

3. Staying the SIP Disapproval will not Significantly Injure Other Parties.

As discussed in Section III.A above, the SIP Disapproval does not on its own impose any emission reductions on sources. As a result, a stay will not directly harm any other party. While a stay would also potentially delay the effective date of the FIP, this is unlikely to result in significant injury to other parties. EPA has recently extended a judicially-enforceable deadline to review Good Neighbor SIPs for three states to December 15, 2023 without any mention of public harm from the delay.[49] Even as a stepping stone to a FIP, while a stay will alleviate imminent and irreparable costs, it will not significantly impact NOx emissions. As discussed above, the FIP is unlikely to be effective until after the start of the current ozone trading season, resulting in an attenuated impact on 2023 emissions. Further, even if projected emission reductions for the full 2023 ozone trading season could be achieved, EPA projects total emission reductions from Minnesota of only 139 tons in 2023. This is unlikely to result in any significant impact on the Cook County maintenance monitor.

4. The Public Interest Lies in Granting a Stay.

As courts have held, there is a public interest enjoining inequitable conduct and in minimizing unnecessary costs to be met from public coffers. *See, e.g. B & D Land & Livestock Co. v. Conner*, 534 F. Supp. 2d 891, 910 (N.D. Iowa 2008). Here, the public interest supports a stay.

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[47] See Comments of U. S. Steel, EPA-HQ-OAR-2021-0668-0798 (June 27, 2022); Comments of Xcel Energy, EPA-HQ-OAR-2021-0668-0411 (June 23, 2022); Comments of Minnesota Power, EPA-HQ-OAR-2021-0668-0539 (June 23, 2022); Comments of SMMPA, EPA-HQ-OAR-2021-0668-0351 (June 22, 2022); Comments of Cleveland-Cliffs Inc., EPA-HQ-OAR-2021-0668-0405 (June 23, 2022)

[48] 88 Fed. Reg. 9336 at 9362.

[49] *See* Joint Notice of Second Stipulated Extension of Consent Decree Deadlines, Doc. 33, *Downwinders at Risk v. Regan*, Case No. 4:21-cv-3551-DMR (N.D. Cal. Jan. 30, 2023).

As discussed in Section II.A above, EPA's SIP Disapproval was promulgated through the inequitable exclusion of public participation into the data central to EPA's final rulemaking. The result will be costly public expenditures, both by EPA to promulgate an unnecessary FIP and States to either prepare to implement EPA's FIP or prepare revised SIPs, and well as unnecessary costs borne by Petitioners.

While it was an error for EPA to disapprove Minnesota's SIP based on information not in the record at the time of submission, EPA can ameliorate the harm of this error by staying the effect of its SIP disapproval until the merits of the issues above can be fully evaluated and addressed.

IV. Conclusion

The State of Minnesota has expended substantial effort and resources to regulate the emission of NOx within its borders. Those efforts have successfully reduced State impacts on downwind receptors to a point that Minnesota is not a significant contributor to nonattainment or interference with maintenance of the 2015 ozone standard in any state. Based on the best available data and modeling science available at the time, Minnesota assessed its impact on downwind states, as it was required to do under the Clean Air Act, and appropriately concluded that it was not interfering with maintenance of attainment in any state. EPA has identified no error or omission in Minnesota's analysis. Nonetheless, based on data that was not available at the time, and in fact was not available to the public until February 2023, EPA partially disapproved Minnesota's Good Neighbor plan for the sole reason that, based on EPA's own modeling, it found a single maintenance receptor in Cook County, Illinois that Minnesota state emissions were impacting at a maximum level of 0.85 ppb. Neither Minnesota, nor Petitioners, were given an opportunity to comment on EPA's modeling, fully evaluate it, or even see it, until EPA published its final SIP Disapproval. While a complete analysis of EPA's modeling would require months, based on Petitioners' review of the data specific to them, and based on expert evaluations by Alpine Geophysics of the modeling and data EPA has provided, EPA's results likely overstate the impact Minnesota is having on the Cook County monitor. Because Petitioners have provided new information that reveals flaws in EPA's emissions inventory for Minnesota and bias in EPA's modeling of the lone monitor that links Minnesota emissions to a downwind state, Petitioners have raised material new data undermining the central basis for EPA's disapproval of prong 2 of Minnesota's SIP. Petitioners therefore request that EPA grant reconsideration of its partial SIP disapproval for Minnesota and approve Minnesota's 2018 SIP. Further, to avoid the significant and irreparable harm to Petitions arising from EPA's erroneous disapproval of prong 2 of Minnesota's SIP, EPA should stay the effectiveness of its SIP Disapproval as applied to prong 2 of Minnesota's SIP pending reconsideration and pending judicial review.

Dated: April 14, 2023

Respectfully submitted,
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Attachment A

TECHNICAL REVIEW OF THE ENVIRONMENTAL PROTECTION AGENCY'S DENIAL OF MINNESOTA'S 2015 OZONE TRANSPORT SIP

Prepared by:
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April 2023

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DOCUMENT OBJECTIVE

The objective of this document is for Alpine Geophysics, LLC to provide technical review and professional opinion of Minnesota Pollution Control Agency's (MPCA) SIP revision to address Clean Air Act (CAA) Section 110(a)(2)(D)(i)(I) and the Environmental Protection Agency's (EPA) final action to disapprove the Minnesota State Implementation Plan (SIP) published on February 13, 2023 in the Federal Register.

This document is formatted into three sections that discuss our review and assessment of the following issues:

A. Whether, given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states;
B. Whether U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary; and
C. Whether the Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

At the end of this document, we also provide a summary of conclusions (Section D) and a regulatory and legislative timeline of actions taken on Minnesota's 2015 ozone SIP for reference (Section E).

A. Given time to reassess, MPCA could demonstrate no linkage and/or no significant impact on attainment and maintenance in downwind states.

EPA provided little time for MPCA to review the significant amount of technical information and associated calculations that were used to justify their disapproval of the Minnesota SIP, especially since EPA used a distinct and largely unrelated modeling platform, emissions inventory, and air quality model to justify its action instead of assessing the platform submitted by MPCA in support of its SIP. Notwithstanding the fact that four years and four months passed since the original Minnesota SIP was submitted to EPA, had appropriate time been given to MPCA to review and address EPA's final disapproval, MPCA could have addressed significant flaws in EPA's modeling that EPA itself should have addressed prior to finalizing any SIP disapproval.

It is our opinion that the U.S. EPA should have approved the MPCA's SIP when it was submitted in 2018. However, since EPA has put forward new modeling, we have reviewed this modeling and found several issues with the emissions that EPA used in the new modeling that weigh against using it as a basis for disapproving the Minnesota SIP.

1. EPA inappropriately revised the emission inventory and conducted new air quality modeling for SIP disapprovals without allowing a meaningful opportunity for stakeholder review and comment.

EPA's revisions to the emission inventory used in the modeling it previously has conducted for historic transport rules raises an administrative concern about public review and comment.

EPA notes in the proposed SIP disapprovals that, after the modeling it conducted in support of earlier transport rules, e.g., CAIR, CSAPR, CSAPR Update, CSAPR Closeout, and Revised CSAPR Update, the agency revised the emission inventory used in the modeling to assess the efficacy of prior transport rules. EPA conducted new modeling using this revised inventory and 2016v2 modeling platform. The agency describes the process as follows:

> *Following the Revised CSAPR Update final rule, the EPA made further updates to the 2016 emissions platform to include mobile emissions from the EPA's Motor Vehicle Emission Simulator MOVES3 model and updated emissions projections for electric generating units (EGUs) that reflect the emissions reductions from the Revised CSAPR Update, recent information on plant closures, and other sector trends. The construct of*

the updated emissions platform, 2016v2, is described in the emissions modeling technical support document (TSD) for this proposed rule.[1]

In December 2021, and in response to EPA requests for inventory review and updates[2,3,4], MPCA and other stakeholders submitted detailed comments on the 2016v2 emission inventory platform to correct errors that existed in that platform. EPA's declared efforts to revise this emission inventory platform at this time raised the question about whether EPA intended to update the modeling that has been used as the basis for the SIP disapprovals and the proposed FIP – but only in support of the final rule. EPA's own summary[5] of the comment process includes the statement that "by spring of 2021 it was necessary to make updates to the inventories to perform credible / defensible modeling in CY2021". In this summary, numerous and significant emission, control, and projection factor changes were requested and only with release of the final SIP denials were the changes shared by EPA for review.

As part of these comments, MPCA submitted comments on the 2016v2 emissions modeling platform (EMP) relative to three areas of improvement within Minnesota:

1. Non-electricity generation stationary (non-EGU) point source emissions controls
2. Future year emissions projections for various point and non-point inventory sectors
3. Stationary point EGU growth rate differences between the ERTAC vs IPM models

Non-EGU point source emissions controls

LADCO worked with member states to identify the highest-emitting sources and applicable control technology information for non-EGU stationary point sources in the region. They generated a spreadsheet with the highest-emitting non-EGU sources in 2016 for each LADCO state, including Minnesota, which also included state updates on emissions control information for listed sources.

A provided spreadsheet identified control information and future emission rate changes for several Minnesota sources within the 2016v2 EMP. The control information identified accounts for the installation of low NOx burners at the taconite facilities in Minnesota as part of the Regional Haze Taconite FIP. Based on MPCA estimates, just under 11,000 tpy in NOx reductions were expected due to the controls required by the Taconite FIP. MPCA noted the importance of

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[1] See: IN, IL, MN, OH, and WI proposal at 87 Fed. Reg. 9838 at 9840
[2] http://views.cira.colostate.edu/wiki/wiki/11208#September-21-2021
[3] https://cleanairact.org/wp-content/uploads/2021/10/Wayland_Monitoring-Modeling-and-Emission-Inventory-Updates_9-30-21-1.pdf
[4] https://www.epa.gov/air-emissions-modeling/2016v2-platform
[5] https://gaftp.epa.gov/Air/emismod/2016/v2/reports/comments/Summary_of_2016v2_comments_by_sector_01312022.pdf

having these significant reductions included in the EPA EMP for non-EGUs and requested that EPA do so.

Below is a summary of approximate NOx emission changes for these sources.

- 2,100 tpy at Minorca Mine
- 2,300 tpy at Hibbing Taconite
- 700 tpy at United Taconite
- 3,600 tpy at US Steel Keetac
- 2,100 tpy at US Steel Minntac

Future year emissions projections for various point and non-point inventory sectors

LADCO used US EPA-generated emissions projection reports and identified a list of SCCs that they believed had incorrect future year projection rates. The 2016v2 EMP projection rates were not found consistent either with real-world emissions trends or regional emissions projection information. It was requested that EPA replace the 2016v2 EMP projections for these sources with the updated rates provided by LADCO.

A spreadsheet was provided that included the list of the SCCs with alternative projection information and LADCO comments on the sources of the alternative information.

Stationary point EGU growth rate differences between the ERTAC vs IPM models

LADCO recognized that EPA used the Integrated Planning Model (IPM) to estimate future year EGU emissions, and that the IPM projection methodology differed from the Eastern Research Technical Advisory Committee (ERTAC) EGU model that is endorsed by the MJOs and most of the states in the eastern half of the country. Minnesota noted support for the use of ERTAC EGU projections in the 2016v2 EMP and asked EPA to consider replacing IPM projections with ERTAC EGU projections for sources in the LADCO region in subsequent modeling platforms.

While most states urged EPA to rely on modeling that accurately reflects current on-the-books regulatory requirements and up-to-date emission inventories, they also strenuously object to the possibility that EPA would conduct any such additional modeling to support a final rule. Furthermore, these states object to EPA not providing the opportunity for those data to be reviewed, analyzed, commented upon, and having those comments addressed by EPA in advance of any final decision on the subject SIP disapproval (or for that matter the related FIP). These concerns were also expressed in July 2021 by several MJOs (WESTAR, LADCO, SESARM, MARAMA, and CENSARA).[6]

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[6] https://www.regulations.gov/comment/EPA-HQ-OGC-2021-0692-0012

EPA's Previously Unreleased 2016v3 Modeling Platform

EPA's newest emissions inventory and modeling platform are of central relevance to EPA's final rule. The SIP Disapproval itself identifies EPA's "updates to the 2016v2 inventories and model design to construct a 2016v3 emissions platform which was used to update the air quality modeling" and used "this updated modeling to inform its final action on these SIP submissions.[7]" These data and modeling in fact form the basis for EPA's final disapproval of Minnesota's SIP[8] (finding Minnesota's analysis "ultimately inadequate" in light of EPA's "more recent air quality analysis"). This issue also arose only with the publication of the final SIP Disapproval. EPA's publication of its revised emissions inventory and modeling did not occur until then, and states had no access to the data, the modeling, or even the results of EPA's modeling until that time.

In the limited time that states have had with the modeling data, significant errors have been identified. A robust public comment process for these data is necessary to correct all significant errors to ensure that EPA's regulatory decisions are based on valid and accurate information. Within Minnesota alone, some of these errors include the following:

- EPA incorrectly included NOx emissions of 2,822 tons in 2023 for Northshore Mining Co. – Silver Bay in the future year air quality modeling and associated significant contribution calculations but not in the engineering analysis used to calculate state level EGU budgets. The subject boilers have been idled since October 2019 and are expected to have zero emissions in 2023;

- EPA predicts zero emissions at Minnesota Power's Laskin Energy Center units that have been converted to natural gas and expect continued MISO dispatch to support the renewables transition and regional grid needs / constraints;

These errors, and many like these presumed in other states in the modeling platform, may significantly impact the results of EPA's analysis and could be the difference in nonattainment and maintenance determinations or whether Minnesota is having a downwind effect on the lone Illinois maintenance monitor that subjects Minnesota to the Good Neighbor provisions of the Clean Air Act.

It is our opinion that the absence of inclusion of Minnesota's and other stakeholder's valid EMP revision submissions, as requested by EPA, and without a rerun of the air quality model in both the base and projection year simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change

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[7] 88 FR 9339
[8] 88 FR 9357

nonattainment designations and linked significance using an updated platform, and needs to be considered before making any final decision on denial of MPCA's SIP.

2. The Cook County, Illinois monitor to which Minnesota is linked, is located at the interface of land and water along Lake Michigan and is not properly characterized by EPA's supporting modeling.

EPA did not make a bias adjustment for the only receptor that EPA found "links" Minnesota to downwind interference with maintenance. Observed values at this location (the Alsip/Village Garage monitor) demonstrate significant model overprediction, justifying the need for adjustments to address bias. While EPA has recently investigated bias in southern Lake Michigan, this assessment selectively analyzed only one monitor, which was not representative of the bias observed at the Village Garage monitor. The failue to adequately address bias in EPA's modeling resulted in an overprediction of ozone. Adjusting for this bias supports the conclusion that the Alsip monitor models in attainment of the 2015 ozone NAAQS and therefore Minnesota is not interfering with maintenance at this monitor. EPA's ozone attainment modeling guidance states that:

> *"[t]he most important factor to consider when establishing grid cell size is model response to emissions controls. Analysis of ambient data, sensitivity modeling, and past modeling results can be used to evaluate the expected response to emissions controls at various horizontal resolutions for both ozone and PM2.5 and regional haze. If model response is expected to be different (and presumably more accurate) at higher resolution, then higher resolution modeling should be considered. If model response is expected to be similar at both high and low(er) resolution, then high resolution modeling may not be necessary. The use of grid resolution finer than 12 km would generally be more appropriate for areas with a combination of complex meteorology, strong gradients in emissions sources, and/or land-water interfaces in or near the nonattainment area(s)"*

EPA's modeling in support of the SIP disapprovals simulated a national domain using a 12km grid resolution domain wide. While this makes running a national, regional simulation easier from a technical perspective, it neglects the important issue of the complex meteorology and/or land-water interfaces in or near the nonattainment or maintenance monitors of interest. Indeed, EPA's choice of a 12km grid is an arbitrary choice in contravention of its own guidance when modeling Illinois monitors in Cook County because these monitors are at land-water interfaces.

Photochemical modeling along coastlines is complex for two reasons. First, the temperature gradients along land/water interfaces can lead to localized on-shore/off-shore flows; and

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secondly, the photochemical model formulation spreads the emissions in a grid cell throughout the full grid volume of the cell.

Figure 1 presents a unique area along Lake Michigan that is challenged by these complex meteorologic issues at land-water interfaces. For the Cook County, Illinois monitor with which Minnesota is linked in this final rule, EPA's published model performance evaluation (MPE) metrics for ozone have been reviewed by Alpine on a day-specific basis.

Figure 1. Lake Michigan shoreline monitors located on land/water interface in Illinois.

Studies indicate that air quality forecast models typically predict large summertime ozone abundances over water relative to land and that meteorology around Lake Michigan is distinctly unique; both shortcomings warrant individualized attention and a finer grid resolution to best explore actual conditions.[9,10,11]

The 3x3 neighborhood of grid cells used in determining the design values of the relative response factor (RRF) at land-water interface monitors extends into the noted water bodies. Under current guidance, the top ten modeled days within this 3x3 matrix are used in determining this RRF for each monitor with any cell identified as 50 percent or more water, except for cells including monitors, which are omitted from the calculations.

Table 1 below provides a list of top 10 days at monitor 170310001 (Alsip/Village Garage), the Cook County monitor in Illinois to which Minnesota is linked, and comparisons of daily modeled

[9] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[10] Abdi-Oskouei, M. , and Coauthors , 2020: Sensitivity of meteorological skill to selection of WRF-Chem physical parameterizations and impact on ozone prediction during the Lake Michigan Ozone Study (LMOS). J. Geophys. Res. Atmos., 125, e2019JD031971, https://doi.org/10.1029/2019JD031971.
[11] McNider, R. T. , and Coauthors, 2018: Examination of the physical atmosphere in the Great Lakes Region and its potential impact on air quality—Overwater stability and satellite assimilation. J. Appl. Meteor. Climatol., 57, 2789–2816, https://doi.org/10.1175/JAMC-D-17-0355.1.

maximum daily average 8-hour ozone concentrations (highlighted in green) and observations on the same date in 2016 (highlighted in blue). These are the dates selected in EPA's modeling to represent the highest modeled days used in estimating future year design values.

As can be seen in Table 1 below, several days selected for RRF calculation have modeled ozone concentrations that fall outside of normally acceptable normalized bias (NBias) boundaries (±15%), here as the result of over (positive bias) predictions compared to observed concentrations on those days. In fact, at the monitor example below, seven of the ten selected days fall outside of the ±15% bias metric (highlighted in orange in the Table) with a maximum normalized bias of 93.60% (observation was 45.25 ppb and modeled concentration was 87.60 ppb; a difference of over 42 ppb).

When these dates are used, EPA's calculation of future year DV is 68.2 ppb (average) and 71.9 ppb (maximum) using the average RRF of 0.9349, identifying this as a maintenance monitor.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160719	73.25	91.07	83.28	0.9144	24.33
2	20160723	45.25	87.60	81.46	0.9298	93.60
3	20160726	64.33	84.02	80.98	0.9637	30.61
4	20160810	85.88	81.35	77.20	0.9490	-5.27
5	20160803	74.38	81.04	75.31	0.9293	8.96
6	20160725	61.88	80.86	76.84	0.9503	30.67
7	20160722	54.50	79.83	76.28	0.9556	46.48
8	20160718	60.75	79.69	76.94	0.9655	31.18
9	20160804	63.75	76.21	66.23	0.8691	19.54
10	20160603	73.63	75.74	69.82	0.9219	2.87
Avg					**0.935**	

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.935	0.935
Future 2023 DV (ppb)	68.2	71.9

Table 1. List of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

If instead a list of the top 10 days with Nbias values within normal acceptable normalized boundaries (±15%) are used, an alternate RRF value is generated, and future year average and

maximum design values used in the nonattainment / maintenance designation process are recalculated.

Table 2 presents a list of top 10 days where the Nbias value is less than the acceptable ±15% normalized bias boundaries. As is seen in this table, all Nbias values fall within the parameters of the acceptable range and dates from the original top 10 list that were already within the boundaries have been maintained and are now the top 3 modeled days in the new list.

	Monitor 170310001 – Alsip/Village Garage (Cook Co, Illinois) **Top 10 RRF - Base Dates (Modeled) –Bias Adjusted - No Water - 3x3**					
		Ozone (ppb)				
Order	**Date**	**Obs**	**Base DV**	**Future DV**	**RRF**	**NBias (%)**
1	20160810	85.88	81.35	77.20	0.9490	-5.27
2	20160803	74.38	81.04	75.31	0.9293	8.96
3	20160603	73.63	75.74	69.82	0.9219	2.87
4	20160618	67.38	74.79	68.50	0.9158	11.00
5	20160619	76.25	72.60	62.88	0.8662	-4.79
6	20160727	68.75	73.92	68.92	0.9324	7.51
7	20160625	68.13	72.99	66.03	0.9046	7.14
8	20160624	74.88	70.49	66.47	0.9430	-5.86
9	20160802	62.50	71.65	66.87	0.9333	14.64
10	20160524	73.50	69.50	64.27	0.9248	-5.44

	Average	**Maximum**
Modeled 2016 DV (ppb)	73.0	77.0
Average RRF	0.922	0.922
Future 2023 DV (ppb)	67.3	70.9

Table 2. Alternate bias adjusted list of top 10 days at the Alsip/Village Garage monitor (170310001) in Illinois used in RRF and resulting calculated design values (ppb).

As a result of this bias adjusted calculation, the Alsip / Village Garage monitor located in Cook County, Illinois (170310001) has an average RRF of 0.922, resulting in an average 2023 DV of 67.3 ppb and a maximum DV of 70.9 ppb, identifying this monitor as attainment of the 2015 ozone NAAQS.

Under Step 1 of the ozone transport framework established by EPA, this monitor would not be considered as part of the list of receptors in the significant contribution calculation and therefore any linkages from upwind state contributions would be irrelevant.

Since this is the only monitor in which Minnesota is linked as a significant contributor under EPA's modeling, this linkage would be broken, and Minnesota should be removed from the list of contributing states to downwind receptors.

In the Response to Comments document from the rule, EPA attempted to address the bias issue by preparing an analysis at select monitors in the modeling domain. Specifically, EPA notes[12] that,

> *"Even though the EPA disagrees with commenter's assertion to "throw out" specific days at individual monitors for which model performance does not meet the criteria, out of an abundance of caution, the EPA performed a sensitivity analysis for selected receptors in which the projected 2023 DVs and contributions were recalculated after removing individual days that fell outside the Emery et al., criteria for normalized mean bias and/or normalized mean error. The EPA chose receptors in Coastal Connecticut, the Lake Michigan area, Dallas, and Denver for this analysis. The specific receptors included in this sensitivity analysis are Stratford, Connecticut, Chicago/Evanston, Illinois, Dallas/Denton, Texas, and Denver/Rocky Flats, Colorado."* (emphasis added)

While we agree with EPA's technical approach and calculations in their Chicago/Evanston example provided, EPA's selection of the Evanston monitor is questionable as it is the only monitor out of ten in Cook County, Illinois (three which are identified as maintenance) where performance-based recalculation results in higher design values. This is also not the unique, individual monitor to which Minnesota is exclusively linked. Table 3 presents the ten Cook County, Illinois monitors in EPA's modeling results[13].

As presented in Table 2, using bias-adjusted design values for the individual receptor with which Minnesota is linked (170310001), this monitor is calculated to be in attainment of the 2015 ozone NAAQS in 2023. This decrease is also seen in the remaining Cook County monitors that EPA did not consider in its response to comments on the issue.

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[12] See pg. 196, https://www.epa.gov/system/files/documents/2023-03/Response%20To%20Comments%20Document%20Final%20Rule.pdf

[13] https://www.epa.gov/system/files/documents/2023-03/Final%20GNP%20O3%20DVs_Contributions.xlsx

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			Upwind State Contribution (ppb)							
Site ID	2023 Avg DV	2023 Max DV	IN	IA	MI	MN	MO	OH	TX	WI
170310001	68.2	71.9	7.11	0.90	1.16	0.85	0.37	0.68	1.09	2.34
170310032	67.3	69.8	8.22	0.79	1.15	0.60	0.62	1.39	1.40	2.21
170310076	67.6	70.4	6.46	0.80	1.07	0.73	0.49	0.62	1.33	2.49
170311003	64.1	64.7	5.70	0.72	1.03	0.37	0.84	1.22	1.67	2.13
170311601	63.8	64.5	5.85	0.61	2.03	0.59	0.44	1.49	0.78	1.63
170313103	58.4	59.6	4.95	0.38	1.44	0.44	0.46	1.08	0.49	2.32
170314002	64.2	67.3	6.71	0.59	1.48	0.62	0.34	1.09	0.95	3.00
170314007	66.8	68.7	5.33	0.41	1.53	0.49	0.53	1.19	1.03	2.81
170314201	68.0	71.5	5.42	0.42	1.56	0.50	0.54	1.21	1.05	2.86
170317002	68.5	71.3	6.55	0.69	1.00	0.38	1.39	1.04	1.95	2.24

Table 3. Future year design values (ppb) and significant contribution calculations of upwind states to monitors in Cook County, Illinois.

Table 4 demonstrates that the Evanston monitor (170317002) in which EPA used to illustrate a noted increase in design value calculations using a bias adjustment calculation was the only monitor out of the ten where the average and maximum design values increased. Had EPA selected any other monitor from Cook County to demonstrate the bias adjustment, their conclusion may have been different than presented in the Response to Comment document.

			EPA Final Rule		Recalculated w/ Bias Adj		
Site ID	State	County	2023 Avg DV	2023 Max DV	2023 Avg DV	2023 Max DV	Bias Adj DV Change
170310001	Illinois	Cook	68.2	71.9	67.3	70.9	Decrease
170310032	Illinois	Cook	67.3	69.8	66.8	69.3	Decrease
170310076	Illinois	Cook	67.6	70.4	65.9	68.7	Decrease
170311003	Illinois	Cook	64.1	64.7	63.3	64.0	Decrease
170311601	Illinois	Cook	63.8	64.5	63.3	63.9	Decrease
170313103	Illinois	Cook	58.4	59.6	58.4	59.6	No Change
170314002	Illinois	Cook	64.2	67.3	63.2	66.3	Decrease
170314007	Illinois	Cook	66.8	68.7	66.7	68.5	Decrease
170314201	Illinois	Cook	68.0	71.5	67.3	70.7	Decrease
170317002	Illinois	Cook	68.5	71.3	69.0	71.8	Increase

Table 4. EPA final rule and bias-adjusted future year design values (ppb) of monitors in Cook County, Illinois.

Additionally, the LMOS 2017 study[14] shows that for Lake Michigan coastal monitors the air quality model even at a 4 km resolution does not simulate the proper timing and structure of the land/lake breeze or the inland penetration of elevated ozone concentrations. A review of this LMOS study[15] states "To reproduce the timing and magnitude of the ozone time series at coastal monitors, ozone production over the lake must be correctly simulated; furthermore, details of the lake breeze must be accurate——timing, horizontal extent, and vertical structure." Based on recommendations from the LMOS 2017 study research team, a horizontal resolution of at most 1.3 km is required to reasonably resolve the complex meteorology of the air/water interface for the great lakes and coastal ocean areas. The LMOS 2017 Study researchers believe that a 1.3 km grid spacing will assist in the resolution of the large ozone concentration gradients that often occur along the shoreline as well as the inland penetration of the lake breeze circulation.

As the Alsip / Village Garage example shows, days where modeled ozone was predicted at concentrations differing up to ± 42 ppb are being used to estimate future year ozone concentrations and to make determinations of nonattainment, maintenance, and significant contribution from upwind sources.

Furthermore, to adequately capture the inland penetration of the lake breeze, the LMOS report also cites the need for accurate Lake Michigan water temperatures and correct model physics options. EPA's use of the Pleim-Xiu Land Service Model (LSM) does not adequately capture the lake breeze inland penetration. A review of wind vector observations (from the Meteorological Assimilation Data Ingest System (MADIS) network) compared to modeled wind vectors on RRF and significantly contributing days at nonattainment monitors highlights the differences in wind direction and speed during many hours of these predicted high ozone episodes.

On many days with relatively simple meteorology, EPA-developed wind fields using the Weather Research and Forecasting (WRF) Model agree with the MADIS observed winds. However, the modeled winds have strong disagreement with the observed meteorology on June 15, July 7, July 27 and August 4, 2016, the four days when the CAMx model predicted the highest ozone concentrations and are thus used in estimating RRFs and future year ozone design values. The following presents an example on August 4, 2016, a day within the top ten highest model estimated MDA8 ozone concentrations at the Alsip / Village Garage monitor.

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[14] https://www.ladco.org/wp-content/uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf

[15] Stanier, C. O., & et al. (2021, November). Overview of the Lake Michigan Ozone Study 2017. BAMS, 19.

In Figure 2 below, the black wind vectors are the wind fields used in the CAMx model. For clarity only every third grid cell is presented. The red vectors are the hourly observed wind vectors from the MADIS archive. The hourly results from 1300 CDT through 1600 CDT are presented in these Figures. The observations clearly show a broad persistent land to lake flow along the western shoreline while the model shows a persistent lake to land flow in this same region during this same period. For this timeframe, when the model is estimating the highest ozone for the ozone season at this receptor, the model has the winds flowing from the lake to the shore while the observations are winds flowing from the shore to the lake.

Figure 2 demonstrates that observed winds (red arrows) are seen moving from land to lake along the western shoreline of Lake Michigan, typically associated with clearing events and lower ozone levels in areas in and around Chicago. In contrast, the model (black arrows) shows a lake to land flow, typically associated with higher model predicted ozone concentrations due to the higher reactive photochemistry over water bodies.

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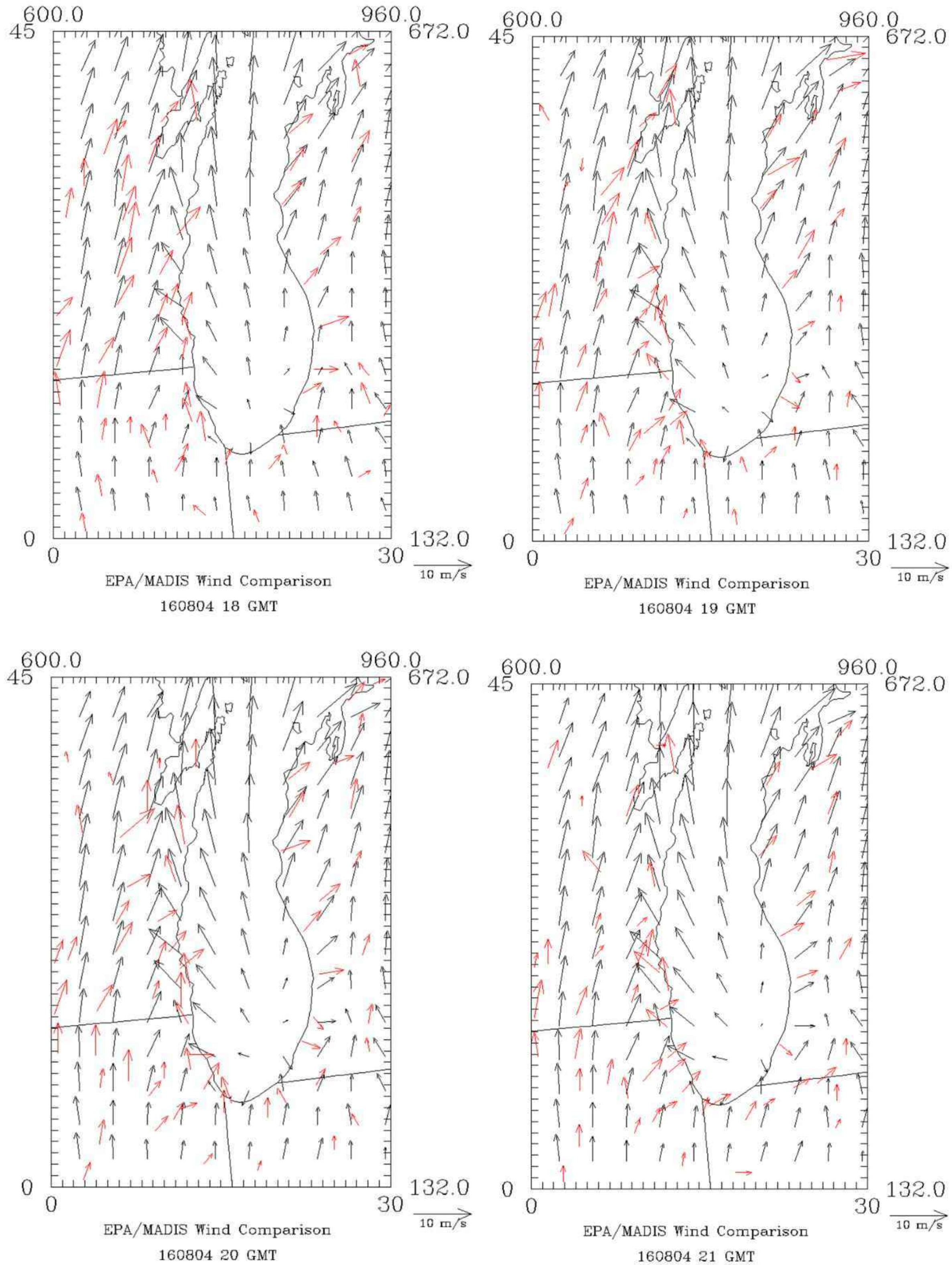

Figure 2. Model estimated (black) and observed (red) winds in the Lake Michigan area at 1300 CDT (top left), 1400 CDT (top right), 1500 CDT (bottom left), and 1600 CDT (bottom right) on August 4, 2016.

These large differences in observed and modeled wind directions are altering the concentration calculations as well as the source/receptor relationships (e.g., determining which sources are "upwind") of the Illinois monitors. As a result, the model cannot accurately reproduce the chemical processes involved with ozone formation. The erroneous modeled meteorological conditions fundamentally change the ozone formation chemistry and modeled source contributions as the chemical transport model predicts more emissions coming from the Chicago urban area than likely the case consistent with the observed wind fields.

When the model is having difficulty resolving fundamental flow patterns in this region with this grid size resolution, EPA needs to reconsider the merit of using the model with this configuration to determine nonattainment status in Step 1 as well as linked significant contributors at receptors in this region under Step 2. For these reasons, EPA must consider finer grid resolution modeling over the Lake Michigan domain to adequately capture ozone formation and significant contribution at receptors located on complex land-water interfaces because model evaluation shows that the model fails to adequately characterize ozone production at these monitors.

Absent a wholesale revision of EPA's modeling protocol, it is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

3. EPA is obligated to address VOC emissions as a critical factor that is influencing ozone nonattainment/maintenance monitors in Illinois

EPA's modeling fails to account for VOC-limited conditions in the Lake Michigan region. Recent information supports the conclusion that VOC-limited conditions in the regional are much more significant that EPA has assumed. This results in EPA's analysis overemphasizing upwind NOx contributions from Minnesota on ozone values at the Alsip/Village Garage monitor and an underemphasis on local VOC contributions, which can be more effectively used to control ozone.

In addition to grid size resolution and complex meteorology issues, modeling performed by EPA[16] and the LMOS 2017 study both showed a negative bias in predicted ozone concentrations in the Lake Michigan region. LMOS 2017 study researchers have experimented with increasing

[16] EPA-HQ-OAR-2021-0668-0099

anthropogenic VOC emissions and decreasing anthropogenic NOx emissions. These emission changes improved air quality model performance reducing the negative bias. VOC speciation and spatio-temporal release patterns should also be reviewed. This evaluation by the LMOS 2017 research scientists indicates there are significant errors in the quantity and speciation of the VOC/NOx emissions used in the EPA's air quality modeling platform to characterize state contribution to ozone in Step 2 of EPA's analyses linking these states to critical nonattainment monitors.

Several downwind nonattainment monitors in urban areas around Lake Michigan recently have been shown to be largely unresponsive to ozone reduction strategies consisting of regional interstate NOx control and that high ozone days in the region were predominantly VOC-limited in nature. This was demonstrated in multiple ozone episodes extensively evaluated in the Lake Michigan Air Directors Consortium (LADCO) Lake Michigan Ozone Study (LMOS) 2017 study[17] where ozone precursor measurements indicated relative increases in VOC concentrations with increases in ozone and where biogenic VOC increases outpaced those of anthropogenic VOC.

In contrast to the peer reviewed research resulting from the 2017 LMOS data collection effort, EPA recently documented its support for additional NOx controls in stating that its "review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[18] However, the current situation is that the modeling as conducted does not accurately characterize ozone levels on high ozone days, underpredicting by 10 + ppb, which is a huge error. Other studies indicate that, to better match actual conditions, the model needs less NOx and higher windspeeds at lower levels. The model is therefore demonstrating that less NOx means more ozone and higher ozone concentrations. That further means that, proportionally, the attribution of ozone to out of state NOx predicts a higher impact than is occurring.

The modeled VOC and NOx emission tracers in EPA's Anthropogenic Precursor Culpability Assessment (APCA) modeling can give a general indication of the VOC/NOx sensitivity, but EPA assigning definitive numerical values to that sensitivity provides inaccurate projections, especially using APCA that is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions. As documented in the CAMx v 7.10 User's Guide[19], "when ozone formation is due to biogenic VOC and anthropogenic NOx under

[17] https://www.ladco.org/wpcontent/
uploads/Research/LMOS2017/LMOS_LADCO_report_revision_apr2019_final.pdf
[18] 87 Fed. Reg. 20,076
[19] https://camx-wp.azurewebsites.net/Files/CAMxUsersGuide_v7.10.pdf, page 177.

VOC-limited conditions (a situation where OSAT would attribute ozone production to biogenic VOC), APCA attributes ozone production to the anthropogenic NOx present. Using APCA instead of OSAT results in more ozone formation attributed to anthropogenic NOx sources and less ozone formation attributed to biogenic VOC sources." Here, it is believed that as applied in this case (with biogenic emissions as an uncontrollable source group), EPA has overestimated the efficacy of NOx controls on these receptors as modeled results have a bias toward attributing more ozone formed to NOx emissions than VOC emissions.

Furthermore, an independent review of EPA's own NOx and VOC contributions challenges the Agency's statement that "[o]ur analysis of the ozone contribution from upwind states subject to regulation under this proposed rule demonstrates that the vast majority of the downwind air quality areas are NOX-limited, rather than VOC-limited."[20] This statement is based on all anthropogenic NOx and VOC emissions from all upwind states and is defined as having NOx emissions contribute to 80% or more of the ozone concentrations modeled at each receptor[21].

EPA further goes on to state that "[t]his review of the portion of the ozone contribution attributable to anthropogenic NOX emissions versus VOC emissions from each linked upwind state leads the Agency to conclude that the vast majority of the downwind air quality areas addressed by the proposed rule under are primarily NOX-limited, rather than VOC-limited."[22]

Alpine's review of EPA's modeled NOx and VOC contributions, by upwind state, focusing on the future year modeled days used in each receptor's Step 2 linkage calculation provides a slightly different picture for monitors around Lake Michigan. As demonstrated in Table 5, of the top future year modeled days impacting significant contribution calculations at the Cook County, Illinois monitor with which Minnesota is linked, more than half of the days are shown to have NOx emission contributions from Illinois below the 80% threshold noted by EPA in determining NOx-limited regions. This is an indicator that on those days, and from anthropogenic sources from those states, VOC controls may demonstrate meaningful impact on ozone concentration reductions at this receptor.

Researchers at the University of Maryland (UMD) have also found in a study of chemical transport model results that by 2023, model predictions of ozone formed under VOC-limited conditions are substantial near the Long Island Sound and the Great Lakes. In a recent presentation[23], they document a source apportionment simulation, conducted with CAMx/APCA on future-year 2023 to determine the major contributing sources and states to air

[20] 87 Fed. Reg. 20053
[21] 87 Fed. Reg. 20076
[22] Id.
[23] https://www.cmascenter.org/conference/2021/slides/allen-northeast-ambient-ozone-2021.pdf

quality within non-attainment areas. Their findings indicate that ozone production under VOC-limited conditions is important at coastal locations near Long Island Sound and the Great Lakes.

		2023 O3	O3N / O3N+O3V Contribution						
Top Day	Date	(ppb)	All	IL	IN	MI	OH	TX	WI
1	07/25/16	70.922	82.4%	81.2%	83.4%	100.0%	-	72.7%	84.1%
2	07/18/16	70.682	69.4%	64.3%	75.6%	-	-	85.9%	67.1%
3	07/19/16	70.668	79.9%	76.7%	83.7%	90.5%	-	80.5%	89.2%
4	08/10/16	67.487	79.4%	70.0%	82.4%	90.4%	86.4%	90.3%	90.6%
5	07/26/16	66.803	80.8%	72.7%	84.0%	90.7%	-	-	90.8%
6	07/23/16	63.295	84.9%	81.2%	84.0%	66.7%	-	89.7%	85.2%
7	08/03/16	61.342	88.8%	84.0%	90.9%	90.4%	92.3%	94.2%	93.8%
8	06/18/16	59.494	86.7%	72.8%	89.4%	90.1%	91.0%	90.9%	89.5%
9	06/03/16	58.730	71.5%	63.2%	73.6%	58.8%	-	74.5%	78.0%
10	08/04/16	58.241	95.0%	92.5%	96.0%	94.7%	97.1%	96.4%	94.9%

Table 5. Modeled ozone contributions to Cook, Illinois monitor (170310001) by percent of emissions from anthropogenic NOx (O3N) compared to emissions from anthropogenic NOx and VOC (O3). Yellow cells indicate contributions of anthropogenic VOC emissions greater than EPA identified "NOx-limited" areas.

Figure 3 presents UMD's findings for model predictions of ozone formation under NOx limited conditions excluding the influence of boundary and initial conditions from the modeling input. As can be seen in these figures, regions around Lake Michigan demonstrate a significantly higher percentage of ozone formed by VOC (blue in color) compared to NOx than most of the eastern US. This observation is seen both on modeled days greater than 60 ppb and on the top ten days of the ozone season (days used in RRF and significant contribution calculations).

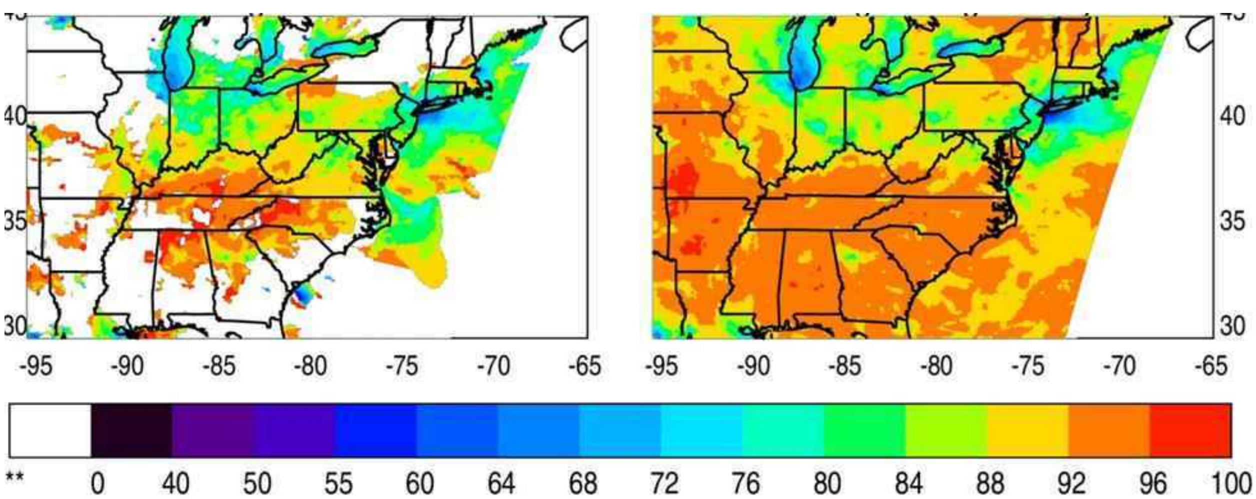

Figure 3. Percent of ozone formed under NOx-limited conditions excluding boundary and initial conditions on all days of MDA8 ozone > 60 ppb (left) and on top ten modeled days (right).

It is also noted that these estimates are a very conservatively high estimate of NOx limited conditions for these coastal areas. In addition to the previous comments highlighting that APCA is known to have a bias toward attributing ozone to NOx emitting anthropogenic sources under VOC sensitive conditions, the UMD analysis footnotes that the APCA run used to generate the results presented in Figure 3 suggests that model configuration led to an underestimation of the contribution of anthropogenic sources to ozone formation, especially during periods of VOC limited chemistry, and as is seen in Figure 3, in the Cook County, Illinois area.

As a result of these findings, EPA is obligated to address the concern that VOC emissions are a factor that is influencing ozone nonattainment and maintenance monitors in Illinois and elsewhere and that EPA determination of ozone nonattainment or maintenance in these areas may be inappropriate for significant contribution and upwind state linkage calculation. It is also our opinion that after review of VOC contribution and limited ozone reduction potential in Chicago and other noted areas, EPA may find that emission reduction plans may fail to justify regional NOx rules for monitors within these transitional and VOC-limited domains.

B. U.S. EPA's revisions to its modeling approach since MPCA's SIP submittal were ancillary.

EPA failed to give appropriate recognition of the merit of the MPCA SIP submitted on October 1, 2018, meeting the statutory deadline for submittal of interstate transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

Under the CAA, on April 1, 2019, MPCA's SIP was deemed to be complete since EPA did not act within the 6 months from the date the SIP was submitted. April 1, 2020, 12 months after the completeness date, was the deadline for EPA to have acted on the MPCA SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[24] In this regard, EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

It wasn't until February 22, 2022, three years and four months after submittal, that EPA finally assessed the Minnesota SIP submittal and proposed disapproval of the SIP[25] as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."

The EPA reiterated this assessment and issued a partial approval on February 13, 2023, in their final rule stating that "Although the EPA acknowledges that Minnesota's Step 3 analysis was insufficient in part because the State assumed it was not linked at Step 2, this is ultimately inadequate to support a conclusion that the State's sources do not interfere with maintenance of the 2015 ozone NAAQS in other states in light of more recent air quality analysis."[26]

[24] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

[25] 87 Fed. Reg. 9838

[26] 88 Fed. Reg. 9357

1. EPA's Failure to Act

MPCA has been disadvantaged by EPA's delay in acting to approve or disapprove its 2015 Good Neighbor SIP, which was submitted to EPA on October 1, 2018. EPA published its proposed disapproval on February 22, 2022, and relied in part on newer, updated modeling performed by the EPA which was not available when MPCA submitted its revised SIP. On February 13, 2023, EPA published its final disapproval and again relied on even newer, updated modeling only released with the rule.

By delaying its final decision on Minnesota's submittal for nearly four and a half years, EPA moved the goal post for Minnesota—an act the DC Circuit rebuked in New York v. EPA, 964 F.3d 1214, 1223 (D.C. Cir. 2020). If EPA were to review and approve or disapprove SIPs within the timeframes required by the CAA, EPA would have conducted its review based on the same modeling and data that was available at the time the SIP was submitted and that has been documented in the sections above. EPA offers no indication that additional material information was available to EPA on April 1, 2020, when agency action on the Minnesota SIP was required that could justify disapproval of the Minnesota SIP.

Further, the updated modeling that EPA now offers to support a SIP review has not been adequately available to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval.

2. EPA has not developed any official guidance for states to follow in submitting a Good Neighbor SIP

The Good Neighbor SIP has been a required SIP element since the implementation of the 1997 8- hour ozone standard. In the intervening years, EPA has issued no official guidance for states to use in developing an approvable Good Neighbor SIP. It is unclear what standard or criteria EPA uses to determine approvability.

In its only direction on the subject, EPA released three 2018 memos that included modeling and discussion on potential flexibilities in approaches that could be used by states in developing their Good Neighbor SIPs. However, EPA has now disapproved MPCA's SIP which was based on EPA's own modeling results from the memo because it "does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state."[27]

[27] 87 FR 9869

From the memos, the only concrete guidance states have been provided is the four-step framework. Applied appropriately in the MPCA SIP, this framework demonstrated that Minnesota was not significantly linked to any downwind nonattainment or maintenance monitor. Since MPCA used EPA's own modeling and four-step approach to prepare its SIP, the SIP was approvable at the time submitted and was approvable when EPA was required to act on the SIP on April 1, 2020.

3. EPA's ever-changing list of nonattainment and maintenance monitors moves the target for Minnesota without offering any basis to reject MPCA's original analysis.

As detailed earlier, MPCA's air quality projections based on the ozone modeling conducted by LADCO in October 2018 was corroborated by EPA's own contribution modeling released with the March 2018 flexibilities memorandum and that showed that Minnesota was not linked to any monitor designated as nonattainment or maintenance for the 2015 ozone NAAQS in 2023. In those two modeling studies, the Cook County, Illinois monitor now linked to Minnesota was calculated to be in attainment for the 2015 ozone NAAQS.

Table 6 provides the average and maximum projected design values from the LADCO modeling that supported the original MPCA iSIP and March 2018 EPA memo modeling for this monitor demonstrating modeled attainment at this location.

			LADCO Modeling		EPA March 2018 Memo	
AQS Site ID	**State**	**County**	**2023 Average DV**	**2023 Maximum DV**	**2023 Average DV**	**2023 Maximum DV**
170310001	Illinois	Cook	62.8	64.6	63.2	64.9

Table 6. LADCO and EPA 2023 ozone design values (ppb) for Minnesota linked Cook County, Illinois monitor from original MPCA SIP and March 2018 EPA memo modeling results.

EPA's proposed disapproval mentions new modeling conducted by EPA in the interim where this Illinois monitor is ultimately identified as a maintenance monitor. Table 7 below provides the average and maximum projected design values from these studies and from the final SIP disapproval for this monitor.

In the proposed SIP disapproval, EPA cites the "results of a prior round of 2023 modeling using the 2016v1 emissions platform which became available to the public in the fall of 2020 in the Revised CSAPR Update." [28] In this Revised CSAPR Update modeling, developed for use with the 2008 ozone NAAQS analyses, monitor 170310001 is identified as a maintenance monitor in

[28] Footnote 94, 87 FR 9869

EPA's results. In EPA's results published in the proposed SIP disapproval[29] and in the final SIP disapproval[30], EPA continued to identify this monitor as a maintenance monitor.

AQS Site ID	EPA Revised CSAPR Update		EPA Proposed SIP Disapproval		EPA Final SIP Disapproval	
	2023 Ave DV	2023 Max DV	2023 Ave DV	2023 Max DV	2023 Ave DV	2023 Max DV
170310001	68.4	72.2	69.6	73.4	68.2	71.9

Table 7. EPA 2023 ozone design values (ppb) for Cook County, Illinois monitor from EPA cited modeling results in proposed and final Minnesota SIP disapproval.

In our opinion, EPA should always rely on the best available modeling at the time that an analysis is conducted and results, whether in a SIP or other, are developed and submitted. In this case, EPA has failed to follow this process and instead continued to move the target and objectives for states that, in Minnesota's case, for over four years and four months had been waiting for a review of their "best available data and analysis".

4. Alternative 1 ppb significance threshold

Neither the LADCO modeling nor EPA modeling released with the March 2018 memorandum indicated that Minnesota would contribute over 1% of the NAAQS to any nonattainment or maintenance monitor in 2023. As a result, Minnesota did not think it necessary to consider using a 1 ppb threshold for significant contribution to downwind receptors, which EPA guidance offered as an option to States.

In the SIP disapproval, EPA further elaborates that following their receipt and review of forty-nine good neighbor SIPs for the 2015 ozone NAAQS, their experience was that no state relying on a 1 ppb threshold provided sufficient information and technical support to justify that an alternative threshold was reasonable[31]. EPA does not indicate how many of the reviewed SIPs used a 1 ppb threshold nor do they indicate on how many state SIPs they provided feedback, if any. They go on to state that this alternate 1 ppb threshold may also be politically inconsistent and impractical under the CAA[32].

As EPA not only failed to provide any feedback to Minnesota on its original October 1, 2018 SIP submittal until the February 22, 2022 proposed SIP disapproval, EPA has also failed to honor its March 2018 guidance[33] which was identified to specifically "*provide analytical information*

[29] Table 5, 87 FR 9868
[30] Table III.B-2, 88 FR 9351
[31] 87 FR 9843
[32] Footnote 33, 87 FR 9843
[33] https://www.epa.gov/sites/default/files/2018-03/documents/transport_memo_03_27_18_1.pdf

regarding the degree to which certain air quality threshold amounts capture the collective amount of upwind contribution from upwind states to downwind receptors or the 2015 ozone NAAQS. It also interprets that information to make recommendation about what thresholds may be appropriate for use in state implementation plan (SIP) revisions addressing the good neighbor provision for that NAAQS."

Minnesota has been denied the opportunity to correct the model inputs that EPA uses as the basis for SIP Disapproval at the 1% threshold and denied the opportunity to update its SIP to take advantage of the 1 ppb threshold that EPA offers States an opportunity to justify in its guidance. While EPA continues to regenerate results based on updated emission modeling platforms and other associated information, states have been omitted from the process, denying them the chance to review updated information and to provide revisions to their SIPs to address those updates.

It is important to note that under all of EPA's cited modeling results, Minnesota contributes under the 1 ppb permitted to be considered from EPA's March 2018 guidance. Table 8 below shows that under none of EPA's four modeling platforms does Minnesota contribute over the 1 ppb threshold to the Cook County monitor.

			Minnesota Contribution (ppb) in 2023			
AQS Site ID	**State**	**County**	**EPA March 2018 Memo**	**EPA Revised CSAPR Update**	**EPA Proposed SIP Disapproval**	**EPA Final SIP Disapproval**
170310001	Illinois	Cook	0.76	0.79	0.97	0.85

Table 8. Minnesota contribution to Cook County, Illinois 2023 ozone design values from documented modeling platforms.

EPA's 2018 flexibility memos, including the opportunity for states to make recommendations to support alternate thresholds for significant contribution, remains an important tool for addressing unique State circumstances in developing their good neighbor SIPs. Disapproving the Minnesota SIP without affording the State an opportunity to utilize this flexibility is unreasonable and should be reconsidered.

C. The Minnesota Pollution Control Agency's state implementation plan revision was approvable based on the state of the science at the time it was submitted to U.S. EPA.

1. Introduction

On October 1, 2018, the Minnesota Pollution Control Agency, after review and comment by EPA Region 5 staff, submitted to the U.S. Environmental Protection Agency a request for revision of Minnesota's State Implementation Plan[34].

The proposed SIP revision addressed Minnesota's responsibilities relating to the "Infrastructure" SIP (iSIP) requirements of sections 110(a)(l) and 110(a)(2) of the Clean Air Act (CAA), as they pertain to the National Ambient Air Quality Standard (NAAQS) for ozone, promulgated in 2015. The CAA requires states to submit an iSIP within three years of the EPA's issuance of a new NAAQS to demonstrate their continued ability to implement, maintain, and enforce the federal standards. The iSIP outlined the statutes, rules, and programs that enable Minnesota to ensure attainment of the 2015 ozone NAAQS. These statutes, rules, and programs had previously been reviewed and approved into Minnesota's iSIP, and the materials included with the iSIP demonstrate that the MPCA did not have further obligations under the iSIP requirements.

The MPCA submission utilized both EPA modeling released with a March 2018 flexibilities memorandum[35] and Lake Michigan Air Directors Consortium (LADCO) modeling results[36]. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

In this document we discuss both the technical and legal validity of MPCA's SIP and EPA's obligation to approve the SIP.

EPA's and LADCO's model projections, along with continuing decreases in the emissions and monitored levels of ozone precursors in Minnesota (nitrogen dioxide and volatile organic compounds), demonstrated that no additional controls or emissions limits were necessary to

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[34] EPA-R05-OAR-2018-0689-0003

[35] https://www.epa.gov/interstate-air-pollution-transport/memo-and-supplemental-information-regarding-interstate-transport

[36] https://www.ladco.org/wp-content/uploads/Documents/Reports/TSDs/O3/LADCO_2015O3iSIP_TSD_13Aug2018.pdf

fulfill Minnesota's responsibilities under the good neighbor provisions for the 2015 ozone NAAQS.

On February 13, 2023, almost four and a half years after the original SIP submittal, EPA finalized a rule in connection with the Air Plan Disapprovals; Interstate Transport Requirements for the 2015 8-Hour Ozone National Ambient Air Quality Standards[37].

EPA notes in this final rule, that these disapprovals would not start a mandatory sanctions clock but rather would establish a 2-year deadline for EPA to promulgate a Federal Implementation Plan (FIP), unless EPA were to approve a subsequent SIP submittal that meets CAA requirements. EPA originally proposed a FIP to be finalized December 15, 2022, in complete disregard for the 2-year period allowed by the CAA for responding to any such SIP disapprovals[38]. This FIP[39] was signed by the Administrator on March 15, 2023, and is still awaiting publication in the Federal Register.

In 2018 EPA issued flexibility guidance for states to follow in development of 2015 ozone standard NAAQS God Neighbor SIPs (GNS). We specifically question how EPA's late disapproval contradicts this guidance.

2. MPCA's Modeling Approach

The modeling performed to support the SIP was performed by LADCO and except for the 2023 projected EGU emissions, was identical to the "EN" platform developed by EPA and followed EPA guidance[40] in preparation of technical material for SIP and SIP-related modeling. The EN platform was used by EPA in its March 2018 flexibility memorandum so that "[s]tates can use these data to develop their implementation plans to assure that emissions within their jurisdictions do not contribute significantly to nonattainment or interfere with maintenance of the 2015 ozone standards in other states."

In our opinion, this platform was technically credible, and a SIP developed from these data should have been approvable by EPA at the time of submission in October 2018. The following sections present our opinions on specific technical aspects of MPCA modeling.

[37] Id.
[38] 87 Fed. Reg 20036
[39] https://www.epa.gov/system/files/documents/2023-03/FRL%208670-02-OAR_Good%20Neighbor_Final_20230314_Signature_ADMIN%20%281%29.pdf
[40] https://www.epa.gov/sites/production/files/2020-10/documents/o3-pm-rh-modeling_guidance-2018.pdf

Base Year

The base year for the MPCA modeling was 2011. 2011 was selected because of data availability and because EPA[41] had noted that 2011 meteorology in the Eastern U.S., including the upper Midwest, was warmer and drier that the climatic norm and represented typical conditions conducive to high observed ozone concentrations in the Midwest and Northeast U.S. It is Alpine's opinion that 2011 was an appropriate modeling year.

Model and Data Selection

This section introduces the models and data sources used in the MPCA. The selection methodology followed EPA's guidance for ozone regulatory modeling[42],[43],[44]. EPA's 2018 modeling guidance[45] lists several criteria for model selection that are paraphrased as follows (pp. 24-27):

- It should not be proprietary;
- It should have received a scientific peer review;
- It should be demonstrated to be applicable to the problem on a theoretical basis;
- It should be used with data bases which are available and adequate to support its application;
- It should be shown to have performed well in past modeling applications;
- It should be applied consistently with an established protocol on methods and procedures;
- It should have a user's guide and technical description;
- The availability of advanced features (e.g., probing tools or science algorithms) is desirable; and

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[41] Air Quality Modeling Technical Support Document for the 2008 Ozone NAAQS Cross-State Air Pollution Rule Proposal. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2015-11/documents/air_quality_modeling_tsd_proposed_rule.pdf

[42] Guidance on the Use of Models and Other Analyses for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Research Triangle Park, NC. EPA-454/B-07-002. April, 2007. (http://www.epa.gov/ttn/scram/guidance/guide/final-03-pm-rh-guidance.pdf).

[43] Draft Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, PM2.5 and Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, RTP, NC. December 3, 2014. (http://www.epa.gov/ttn/scram/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf).

[44] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[45] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29, 2018. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

- When other criteria are satisfied, resource considerations may be important and are a legitimate concern.

It is Alpine's opinion that the models chosen for the MPCA modeling met these criteria and were appropriate for use in the SIP.

Meteorological Modeling

The Weather Research and Forecasting (WRF) Model is a mesoscale numerical weather prediction system designed to serve both operational forecasting and atmospheric research needs[46],[47],[48]. The Advanced Research WRF (ARW) version of WRF was used in the MPCA modeling study. It features multiple dynamical cores, a 3-dimensional variational (3DVAR) data assimilation system, and a software architecture allowing for computational parallelism and system extensibility. WRF is suitable for a broad spectrum of applications across scales ranging from meters to thousands of kilometers. The effort to develop WRF has been a collaborative partnership, principally among the National Center for Atmospheric Research (NCAR), the National Oceanic and Atmospheric Administration (NOAA), the National Centers for Environmental Prediction (NCEP) and the Forecast Systems Laboratory (FSL), the Air Force Weather Agency (AFWA), the Naval Research Laboratory, the University of Oklahoma, and the Federal Aviation Administration (FAA). WRF allows researchers the ability to conduct simulations reflecting either real data or idealized configurations. WRF provides operational forecasting a model that is flexible and efficient computationally, while offering the advances in physics, numerics, and data assimilation contributed by the research community.

WRF is publicly available, has full documentation and has demonstrated success in simulating meteorological conditions in the Upper Midwest.

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[46] Skamarock, W. C. 2004. Evaluating Mesoscale NWP Models Using Kinetic Energy Spectra. *Mon. Wea. Rev.*, Volume 132, pp. 3019-3032. December, 2004. (http://www.mmm.ucar.edu/individual/skamarock/spectra_mwr_2004.pdf).

[47] Skamarock, W. C. 2006. Positive-Definite and Monotonic Limiters for Unrestricted-Time-Step Transport Schemes. *Mon. Wea. Rev.*, Volume 134, pp. 2241-2242. June. (http://www.mmm.ucar.edu/individual/skamarock/advect3d_mwr.pdf).

[48] Skamarock, W. C., J. B. Klemp, J. Dudhia, D. O. Gill, D. M. Barker, W. Wang and J. G. Powers. 2005. A Description of the Advanced Research WRF Version 2. National Center for Atmospheric Research (NCAR), Boulder, CO. June. (http://www.mmm.ucar.edu/wrf/users/docs/arw_v2.pdf)

MPCA used the U.S. EPA 2011 WRF data for this study[49]. The U.S. EPA used version 3.4 of the WRF model, initialized with the 12-km North American Model (NAM) from the National Climatic Data Center (NCDC) to simulate 2011 meteorology. Complete details of the WRF simulation, including the input data, physics options, and four-dimensional data assimilation (FDDA) configuration are detailed in the U.S. EPA 2008 Transport Modeling technical support document[50]. U.S. EPA prepared the WRF data for input to CAMx with version 4.3 of the WRFCAMx software.

It is Alpine's opinion that the U.S. EPA WRF 3.4 meteorological modeling was appropriate for use in the MPCA SIP.

Initial and Boundary Conditions

MPCA used 2011 initial and boundary conditions for CAMx generated by the U.S. EPA from the GEOS-Chem Global Chemical Transport Model[51]. EPA generated hourly, one-way nested boundary conditions (i.e., global-scale to regional-scale) from a 2011 2.0 degree x 2.5 degree GEOS-Chem simulation. Following the convention of the U.S. EPA O3 transport modeling, year 2011 GEOS-Chem boundary conditions were used by LADCO for modeling 2023 air quality with CAMx.

It is Alpine's opinion that the U.S. EPA GEOS-Chem derived initial and boundary conditions were appropriate for use in the MPCA SIP.

Emissions

The 2023 emissions data for the MPCA SIP were based on the U.S. EPA 2011v6.3 ("EN") emissions modeling platform[52]. U.S. EPA generated this platform for their final assessment of Interstate Transport for the 2008 O3 NAAQS. Updates from earlier 2011-based emissions modeling platforms included a new engineering approach for forecasting emissions from Electricity Generating Units (EGUs). LADCO replaced the EGU emissions in the U.S. EPA EN

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[49] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[50] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

[51] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

[52] US EPA. 2017. Technical Support Document: Additional Updates to Emissions Inventories for the Version 6.3 Emissions Modeling Platform for the Year 2023. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-11/documents/2011v6.3_2023en_update_emismod_tsd_oct2017.pdf

platform with 2023 EGU forecasts estimated with the ERTAC EGU Tool version 2.7[53]. ERTAC EGU 2.7 integrates state-reported information on EGU operations and forecasts as of May 2017. The MPCA believes “power sector emissions forecasts must address economic factors, preserve system reliability, and include controls or emission reduction measures justified through some legal framework. It is our understanding that the engineering analysis used by EPA to project EGU emissions to 2023 (version EN of the modeling platform) does not comply with these key requirements. The ERTAC estimates incorporate the key requirements.”[54]

In March 2018 U.S. EPA released it flexibilities memo that described a series of flexibilities that states could consider in developing Good Neighbor SIPs for the 2015 ozone NAAQS. The “[u]se of alternative power sector modeling consistent with EPA’s emissions inventory guidance” is presented in the Analytics section of EPA’s March 2018 memo as a flexibility to consider in preparing a Good Neighbor SIP. This flexibility supports LADCO’s use of the ERTAC EGU model for projecting EGU emissions to 2023. MPCA considers the emissions projections from ERTAC EGU to be more representative of the sources in the Midwest and Northeast than the approach used by U.S. EPA in their 2023 EN modeling platform. As ERTAC EGU is developed in collaboration between regional and state air planning agencies, it includes algorithms and data that have been reviewed by many of the states impacted by interstate O3 transport in the Midwest and Eastern U.S.

Preparation of the emissions data to support photochemical models is a very complicated process that entails the use of a number of different “sub-models” to prepare different emission segments.

Sparse Matrix Operator Kernel Emissions (SMOKE)

The Sparse Matrix Operator Kernel Emissions (SMOKE) is an emissions modeling system that generates hourly gridded speciated emission inputs of mobile, non-road, area, point, fire and biogenic emission sources for PGMs[55],[56]. As with most “emissions models,” SMOKE is principally an emission processing system and not a true emissions modeling system in which emissions estimates are simulated from “first principles.” This means that, except for mobile and biogenic sources, its purpose is to provide an efficient, modern tool for converting an existing base emissions inventory data that is typically at the county or point source level into

[53] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[54] EPA-R05-OAR-2018-0689-0003

[55] Coats, C.J. 1995. Sparse Matrix Operator Kernel Emissions (SMOKE) Modeling System, MCNC Environmental Programs, Research Triangle Park, NC.

[56] UNC. 2018. SMOKE v4.6 User’s Manuel. University of North Carolina at Chapel Hill, Institute for the Environment. Chapel Hill, North Carolina. September 24. (https://www.cmascenter.org/smoke/documentation/4.6/manual_smokev46.pdf).

the hourly gridded speciated formatted emission files required by a Photochemical Grid Model (PGM), like CAMx. SMOKE was used to prepare emission inputs for non-road mobile, non-point (area) and point sources. SMOKE performs three main function to convert emissions to the hourly gridded emission inputs for a PGM: (1) spatial allocation, spatial allocates county-level emissions to the PGM model grid cells typically using a surrogate distribution (e.g., population); (2) temporal allocation, allocates annual emissions to time of year (e.g., monthly or seasonally) and day-of-week (typically weekday, Saturday and Sunday); and (3) chemical speciation, maps the emissions to the species in the chemical mechanism used by the photochemical grid model, most important for VOC and $PM_{2.5}$ emissions.

The primary emissions modeling tool used to create the air quality model-ready emissions was the SMOKE modeling system version 3.7 which was used to create emissions files for a 12-km national grid "12US2" that includes all of the contiguous states.

It is Alpine's opinion that the SMOKE emissions model together with the other EPA emissions was appropriate for use in the MPCA SIP.

Motor Vehicle Emissions Simulator (MOVES)

The motor vehicle emissions were prepared by U.S. EPA using the MOVES 2014a emissions model[57],[58],[59]. MOVES 2014a was the most up to date released motor vehicle emissions processor at the time of the MPCA SIP submission and it is Alpine's opinion that the U.S. EPA MOVES 2014a emissions were appropriate for use in the MPCA SIP.

Eastern Regional Technical Advisory Committee EGU Model

The Eastern Regional Technical Advisory Committee (ERTAC) EGU model for growth was developed around activity pattern matching algorithms designed to provide hourly EGU emissions data for air quality planning. The original goal of the model was to create low-cost software that air quality planning agencies could use for developing EGU emissions projections. States needed a transparent model that was numerically stable and did not produce dramatic changes to the emissions forecasts with small changes in inputs. A key feature of the model

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[57] EPA. 2014a. Motor Vehicle Emissions Simulator (MOVES) – User Guide for MOVES2014. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-055). July. (http://www.epa.gov/oms/models/moves/documents/420b14055.pdf).

[58] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

[59] EPA. 2014b. Motor Vehicle Emissions Simulator (MOVES) –MOVES2014 User Interface Manual. Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency. (EPA-420-B-14-067). July. (http://www.epa.gov/oms/models/moves/documents/420b14057.pdf).

includes data transparency; all of the inputs to the model are publicly available. The code is also operationally transparent and includes extensive documentation, open-source code, and a diverse user community to support new users of the software.

Operation of the model is straightforward given the complexity of the projection calculations and inputs. The model imports base year Continuous Emissions Monitoring (CEM) data from U.S. EPA and sorts the data from the peak to the lowest generation hour. It applies hour specific growth rates that include peak and off-peak rates. The model then balances the system for all units and hours that exceed physical or regulatory limits. ERTAC EGU applies future year controls to the emissions estimates and tests for reserve capacity, generates quality assurance reports, and converts the outputs to SMOKE ready modeling files.

ERTAC EGU has distinct advantages over other growth methodologies because it can generate hourly future year estimates which are key to understanding ozone episodes. The model does not shutdown or mothball existing units because economics algorithms suggest they are not economically viable. Additionally, alternate control scenarios are easy to simulate with the model. Full documentation for the ERTAC Emissions model and 2.7 simulations are available through the MARAMA website[60].

Differences between the EPA and ERTAC EGU emissions forecasts arise from alternative forecast algorithms and from the data used to inform the model predictions. The U.S. EPA EGU forecast used in the 2023 EN modeling used CEM data available through the end of 2016 and comments from states and stakeholders received through April 17, 2017[61]. ERTAC EGU 2.7 used CEM data from 2011 and state-reported changes to EGUs through May 2017. The ERTAC EGU 2.7 emissions used for the modeling represented the best available information on EGU forecasts for the Midwest and Eastern U.S. available during Spring-early Summer 2018.

The “consideration of state-specific information in identifying sources [e.g., electric generating units (EGUs) and non-EGUs] and controls” is one of the potential approaches in EPA’s March 2018 flexibilities memorandum. The use of the ERTAC EGU tool falls squarely within the parameters of this documented flexibility and it is Alpine’s opinion that MPCA’s used of EGU emission projections from this model were appropriate in the MPCA SIP.

[60] http://www.marama.org/2013-ertac-egu-forecasting-tool-documentation

[61] US EPA. 2017. Memorandum: Supplemental Information on the Interstate Transport SIP Submissions for the 2008 Ozone NAAQS under Clean Air Act Section 110(a)(2)(D)(i)(I), Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-10/documents/final_2008_o3_naaqs_transport_memo_10-27-17b.pdf.

BEIS

Biogenic emissions were computed by U. S. EPA based on the same version of the 2011 meteorology data used for the air quality modeling and were developed using the Biogenic Emission Inventory System version 3.61 (BEIS3.61) within SMOKE. The landuse input into BEIS3.61 is the BELD version 4.1 which is based on an updated version of the USDA-USFS Forest Inventory and Analysis (FIA) vegetation speciation-based data from 2001 to 2014 from the FIA version 5.1.

It is Alpine's opinion that the U.S. EPA application of the BEIS model was appropriate for use in the MPCA SIP.

3. Air Quality Modeling

The MPCA modeling used the Comprehensive Air-quality Model with Extensions (CAMx) air quality model[62]. CAMx is a state-of-science "One-Atmosphere" multi-scale photochemical grid model (PGM) capable of addressing ozone, particulate matter (PM), visibility and acid deposition at regional, urban and local scale typically for periods of a year. CAMx is a publicly available open-source computer modeling system for the integrated assessment of gaseous and particulate air pollution. Built on today's understanding that air quality issues are complex, interrelated, and reach beyond the urban scale, CAMx is designed to (a) simulate air quality over many geographic scales, (b) treat a wide variety of inert and chemically active pollutants including ozone, inorganic and organic $PM_{2.5}$ and PM_{10} and mercury and toxics, (c) provide source-receptor, sensitivity, and process analyses and (d) be computationally efficient and easy to use.

The U.S. EPA has approved the use of CAMx for numerous ozone and PM State Implementation Plans throughout the U.S. and has used this model to evaluate regional mitigation strategies including those for most recent national transport rules, such as the Cross-State Air Pollution Rule (CSAPR), CSAPR Update, and the modeling used in justification of denial of the MPCA SIP. The MPCA used Version 6.4, which was released in December 2016. Unlike some of EPA's previous ozone modeling guidance that specified a particular ozone model (e.g., EPA 1991 Guidance[63]) or that specified the Urban Airshed Model (UAM)[64], the EPA now recommends that

[62] User's Guide: Comprehensive Air Quality Model with Extensions version 6.40. Novato, CA. http://www.camx.com/files/camxusersguide_v6-40.pdf

[63] Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-hr Ozone NAAQS". U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Research Triangle Park, N.C. May.

[64] User's Guide for the Urban Airshed Model. Volume I: User's Manual for UAM (CB-IV) prepared for the U.S. Environmental Protection Agency (EPA-450/4-90-007a). Systems Applications International, San Rafael, CA.

models be selected for ozone SIP studies on a "case-by-case" basis. The latest EPA ozone guidance[65] (pp. 24) explicitly mentions the CAMx PGMs as one of the most commonly used PGMs that would satisfy EPA's selection criteria but notes that this is not an exhaustive list and does not imply that it is "preferred" over other PGMs that could also be considered and used with appropriate justification.

The CAMx model is updated regularly to both update the science in the model and to address coding errors (bugs) in the code. CAMx 6.5 was released at the end of April 2018, approximately 6 months prior to submission the MPCA SIP submission. It is customary for regulatory modeling to "freeze" the model version during the modeling process to keep the modeling on schedule.

It is Alpine's opinion that the CAMx 6.4 air quality model along with the EPA EN platform with 2023 EGU's updated to include ERTAC was appropriate for use in the MPCA SIP.

4. Model Performance

MPCA relied on the model performance evaluation (MPE) conducted by the U.S. EPA on the modeling platform that we used for this study[66] to establish validity in the modeling platform. In addition to the MPE for the base year CAMx simulation, the U.S. EPA reported full MPE results for the 2011 WRF modeling[67] used in the CAMx simulations.

It is Alpine's opinion that the EPA WRF and CAMx performance evaluations showed adequate performance and that the modeling was appropriate for use in the MPCA SIP.

5. Source Apportionment

MPCA used the CAMx Anthropogenic Precursor Culpability Assessment (APCA) tool to calculate emissions tracers for identifying upwind sources of ozone at downwind monitoring sites. MPCA

[65] Modeling Guidance for Demonstrating Air Quality Goals for Ozone, PM2.5, an Regional Haze. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Air Assessment Division. Research Triangle Park, NC. EPA 454/R-18-009. November 29. (https://www3.epa.gov/ttn/scram/guidance/guide/O3-PM-RH-Modeling_Guidance-2018.pdf).

[66] US EPA. 2016. Air Quality Modeling Technical Support Document for the 2015 Ozone NAAQS Preliminary Interstate Transport Assessment. Research Triangle Park, NC. https://www.epa.gov/sites/production/files/2017-01/documents/aq_modeling_tsd_2015_o3_naaqs_preliminary_interstate_transport_assessmen.pdf

[67] US EPA. 2014. Meteorological Model Performance for Annual 2011 WRFv3.4 Simulation. Research Triangle Park, NC. https://www3.epa.gov/ttn/scram/reports/MET_TSD_2011_final_11-26-14.pdf.

used the APCA technique because it more appropriately associates ozone formation to anthropogenic sources than the CAMx Ozone Source Apportionment Technique (OSAT). If any anthropogenic emissions are involved in a reaction that leads to ozone formation, even if the reaction occurs with biogenic VOC or NOx, APCA tags the ozone as anthropogenic in origin.

The APCA source apportionment tool has a robust theoretical basis and a long application history and it is our opinion that the APCA tool is appropriate for identifying upwind sources of ozone at downwind monitoring sites.

6. Interstate Transport Provisions – Section 110(a)(2)(D)

This section of the CAA requires SIPs to have provisions prohibiting sources from emitting air pollutants in amounts that would contribute significantly to nonattainment or interfere with maintenance in any other state. These interstate transport requirements are often referred to as “good neighbor SIPs”. The analyses conducted both by LADCO and EPA to support the 2015 ozone good neighbor SIPs show Minnesota does not contribute significantly to air quality problems in any downwind nonattainment or maintenance area. Therefore, no additional controls or emissions limits were required to fulfill Minnesota’s good neighbor obligations.

On March 27, 2018, the EPA published a memo, entitled “Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)”. EPA’s Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the “good neighbor” SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

EPA identifies a four-step framework in the Memo, intended to guide states on how to go about developing good neighbor SIPs:

1. Identify downwind air quality problems;
2. Identify upwind states that contribute enough to those downwind air quality problems to warrant further review and analysis;
3. Identify the emissions reductions necessary (if any), considering cost and air quality factors, to prevent an identified upwind state from contributing significantly to those downwind air quality problems; and
4. Adopt permanent and enforceable measures needed to achieve those emissions reductions.

In Step 1, EPA identifies monitoring sites that are projected to have problems attaining and/or maintaining the NAAQS in the 2023 analytic year. Where EPA’s analysis shows that a site does

not fall under the definition of a nonattainment or maintenance receptor, that site is excluded from further analysis under EPA's 4-step interstate transport framework. For sites that are identified as a nonattainment or maintenance receptor in 2023, we proceed to the next step of our 4-step interstate transport framework by identifying the upwind state's contribution to those receptors.

In Step 2, EPA quantifies the contribution of each upwind state to each receptor in the 2023 analytic year. The contribution metric used in Step 2 is defined as the average impact from each state to each receptor on the days with the highest ozone concentrations at the receptor based on the 2023 modeling. If a state's contribution value does not equal or exceed the threshold of 1 percent of the NAAQS (i.e., 0.70 ppb for the 2015 ozone NAAQS), the upwind state is not ''linked'' to a downwind air quality problem, and EPA, therefore, concludes that the state does not significantly contribute to nonattainment or interfere with maintenance of the NAAQS in the downwind states.

Comparably, in MPCA's SIP submission, they include LADCO's modeling which additionally follows the same transport framework and is corroborated by EPA's modeling with the data released with the March 2018 memo.

Step 1 - 2023 Air Quality Projections

MPCA's reported air quality projections[68] submitted with their SIP were based on the ozone modeling conducted by LADCO. The result of this LADCO 2023 modeling, using methods utilized by EPA and shown in Table 9 below, forecasted that no downwind monitors in the Midwest or Northeast would be nonattainment for the 2015 O3 NAAQS.

[68] Data source Table 5, Attachment 1, EPA-R05-OAR-2018-0689-0003

			LADCO 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	67.2	69.4	78.0	80.0
90013007	Fairfield	CT	67.8	71.6	84.3	89.0
90019003	Fairfield	CT	69.6	72.4	83.7	87.0
90099002	New Haven	CT	67.9	70.5	85.7	89.0
240251001	Harford	MD	69.4	71.8	90.0	93.0
260050003	Allegan	MI	67.1	69.8	80.3	83.0
261630019	Wayne	MI	67.7	69.7	78.7	81.0
360810124	Queens	NY	67.5	69.2	70.0	71.0
361030002	Suffolk	NY	69.8	71.3	83.3	85.0
550790085	Milwaukee	WI	62.1	65.1	78.3	82.0
551170006	Sheboygan	WI	69.3	71.5	84.3	87.0

Table 9. LADCO 2023 ozone design values at EPA identified nonattainment and maintenance monitors in the Midwest and Northeast.

EPA's own modeling[69], released with the March 2018 platform, shown in Table 10, and designed to be used by states in development of their ozone transport SIPs, indicated that in the Midwest or Northeast, two downwind monitors in Fairfield, Connecticut (monitors 90013007 and 90019003), a monitor in Suffolk, New York (36103002), and monitors in Milwaukee (550790085) and Sheboygan (551170006), Wisconsin would be in nonattainment for the 2015 ozone NAAQS.

			EPA 2023 DV		2009-2013 DV	
AQS ID	**County**	**ST**	**3x3 Avg**	**3x3 Max**	**3x3 Avg**	**3x3 Max**
90010017	Fairfield	CT	68.9	71.2	80.3	83.0
90013007	Fairfield	CT	71.0	75.0	84.3	89.0
90019003	Fairfield	CT	73.0	75.9	83.7	87.0
90099002	New Haven	CT	69.9	72.6	85.7	89.0
240251001	Harford	MD	70.9	73.3	90.0	93.0
260050003	Allegan	MI	69.0	71.7	82.7	86.0
261630019	Wayne	MI	69.0	71.0	78.7	81.0
360810124	Queens	NY	70.2	72.0	78.0	80.0
361030002	Suffolk	NY	74.0	75.5	83.3	85.0
550790085	Milwaukee	WI	71.2	73.0	80.0	82.0
551170006	Sheboygan	WI	72.8	75.1	84.3	87.0

Table 10. EPA 2023 ozone design values at nonattainment and maintenance monitors in the Midwest and Northeast.

[69] https://www.epa.gov/sites/default/files/2018-05/updated_2023_modeling_dvs_collective_contributions.xlsx

An additional six monitors in Connecticut (90010017 and 90099002), Maryland (240251001), Michigan (260050003 and 261630019), and New York (360810124) would be considered maintenance monitors in the projection.

In neither the LADCO nor EPA modeling cited in MPCA's SIP revision submission were the two Cook County, Illinois monitors (170314201 and 170310076) from EPA's SIP denial NPR, or the single monitor from EPA's final SIP disapproval action, identified as either nonattainment or maintenance monitors in the 2023 projections.

Step 2 - Significant Contribution to Downwind States

EPA has previously determined that a state contribution to downwind air quality problems below one percent of the applicable NAAQS is insignificant. This screening method was used in previous good neighbor SIP approvals, and other regulatory actions including (most notably) the Cross-State Air Pollution Rule (CSAPR), and the CSAPR update for the 2008 ozone NAAQS and 2012 NAAQS for particulate matter less than 2.5 micrometers in diameter (PM2.5). The one percent screening method was developed through several previous federal notice and comment rulemakings. One percent of the 2015 ozone NAAQS (70 ppb) is 0.70 ppb. Therefore, any state that contributes less than 0.70 ppb to a projected nonattainment or maintenance area in another state is not culpable for those air quality problems.

EPA and LADCO applied the Anthropogenic Precursor Culpability Analysis (APCA) technique in CAMx to identify upwind states culpable for downwind ozone air quality problems. The method accounts for anthropogenic nitrogen oxides (NO_x) and volatile organic carbon (VOC) emissions from all sources in each upwind state affecting projected 2023 ozone concentrations at each downwind air quality monitoring site designated a nonattainment or maintenance receptor. EPA and LADCO conducted the culpability analysis for the period May 1 through September 30, using the 2023 future emission estimates and 2011 meteorology.

Both LADCO and EPA analyses[70] conclude Minnesota is not culpable for ozone nonattainment, or interference with maintenance, in any downwind states. As shown in Table 11, prepared using data from MPCA's SIP[71], LADCO's analysis shows a maximum contribution of 0.45 ppb to the identified maintenance monitors, less than the 0.70 ppb identified as 1% of the NAAQS (70 ppb). EPA's analysis[72] (Table 12) indicates Minnesota contributes most to Milwaukee, Wisconsin monitor site 550790085. At a concentration of 0.40 ppb, this contribution is roughly equal to 0.57% of the 2015 ozone NAAQS.

[70] Data source Table 2, EPA-R05-OAR-2018-0689-0003
[71] Id.
[72] Id.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	67.2	69.4	0.17
90013007	Fairfield	CT	67.8	71.6	0.15
90019003	Fairfield	CT	69.6	72.4	0.11
90099002	New Haven	CT	67.9	70.5	0.16
240251001	Harford	MD	69.4	71.8	0.12
260050003	Allegan	MI	67.1	69.8	0.11
261630019	Wayne	MI	67.7	69.7	0.30
360810124	Queens	NY	67.5	69.2	0.16
361030002	Suffolk	NY	69.8	71.3	0.16
550790085	Milwaukee	WI	62.1	65.1	0.45
551170006	Sheboygan	WI	69.3	71.5	0.27

Table 11. LADCO 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

AQS ID	County	ST	2023 Avg DV	2023 Max DV	MN Contribution (ppb)
90010017	Fairfield	CT	68.9	71.2	0.17
90013007	Fairfield	CT	71.0	75.0	0.15
90019003	Fairfield	CT	73.0	75.9	0.14
90099002	New Haven	CT	69.9	72.6	0.19
240251001	Harford	MD	70.9	73.3	0.13
260050003	Allegan	MI	69.0	71.7	0.11
261630019	Wayne	MI	69.0	71.0	0.31
360810124	Queens	NY	70.2	72.0	0.17
361030002	Suffolk	NY	74.0	75.5	0.18
550790085	Milwaukee	WI	71.2	73.0	0.40
551170006	Sheboygan	WI	72.8	75.1	0.28

Table 12. EPA 2023 O3 design values at nonattainment and maintenance monitors in the Midwest and Northeast and Minnesota's calculated contribution.

For the reasons set forth in this section, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 2018 was technically adequate and appropriate for the purpose it was intended and followed all available EPA guidance on preparing technical modeling for SIP and SIP-related analyses.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted.

D. Summary of Conclusions

For the reasons set forth in this document, it is our opinion that the modeling conducted and cited by MPCA in the development of its 2015 ozone NAAQS transport SIP revision of October 1, 2018 was technically adequate and appropriate for the purpose it was intended and should have been approved by EPA at the time of submission. It is further our opinion that decisions made by EPA to compare MPCA's original submitted modeling to recently updated modeling, developed by EPA over four years and four months later than the original Oct 2018 submission, are inconsistent with EPA precedent.

It is our opinion that in the absence of inclusion of Minnesota's and other stakeholder's valid emission modeling platform revision submissions, as requested by EPA, and multiple reruns of the air quality in both the base year (2016) and projection year (2023) simulations, EPA cannot appropriately identify monitors as nonattainment or maintenance, and in turn, cannot calculate upwind state significant contribution metrics from these same data. Non-EGU emission controls and their associated NOx emission reductions as documented and submitted by MPCA, could be enough to change nonattainment designations and linked significance using an updated platform and needs to be considered before making any final decision on denial of MPCA's SIP.

It is our opinion that EPA's use of modeling with poor performance at critical monitors amounts to an unreliable result when used to establish nonattainment or maintenance monitors under Step 1 or linkages under Step 2 of the 4-step framework. Should more refined modeling be undertaken to review the ozone formation potential at monitors located in these land-water interfaces, results may show that these monitors demonstrate modeled attainment and/or remove significant contribution linkages from upwind states.

It is our opinion that the most recent modeling cited by EPA and used to justify the linkage of Minnesota to one downwind maintenance monitors in Cook County, Illinois has technical issues as it relates to that linked monitor which is located in a complex land-water interface and may require finer grid resolution modeling to adequately capture ozone formation and significant contribution, and that EPA must address the impact of VOC emissions in influencing ozone formation at monitors in Illinois.

It is our opinion that EPA has failed to follow the process by relying on the best available modeling at the time that an analysis is conducted, and results are developed and submitted. Instead, EPA continues to move the target and objectives for states that, in Minnesota's case, for over four years had been waiting for a review of their "best available data and analysis".

It is our opinion that EPA should not have used any updated modeling to support a SIP review while not providing the opportunity for that data to be reviewed, analyzed, and commented on in advance of any final decision on the subject SIP disapproval and that any modeling beyond what was conducted in the original SIP submittal was ancillary to the approval process. However, should EPA decide not to review MPCA's SIP revision on its merit, Alpine recommends that EPA withdraw the SIP disapproval in favor of correcting the technical errors that have been identified in its analysis and to propose an appropriate opportunity for Minnesota to address any deficiencies EPA may find in Good Neighbor Plans implementing the 2015 ozone NAAQS.

It is our opinion that EPA's 2018 flexibility memo has become so instrumental to states in developing their good neighbor SIPs, that EPA's decision to disallow the flexibilities that they themselves outlined in guidance, is unreasonable and should be reconsidered.

Additionally, in our opinion, the MPCA SIP adequately demonstrates that Minnesota is not a significant contributor to any downwind monitor identified as in nonattainment or maintenance for the 2015 ozone NAAQS and is corroborated by EPA modeling which included state-of-science configuration and platform at the time the original SIP was submitted. It is our opinion that the original MPCA SIP was and is approvable.

ALPINE GEOPHYSICS

E. Minnesota 2015 Ozone SIP Timeline

October 1, 2015 – EPA finalized the revised 2015 ozone NAAQS. Pursuant to CAA section 110(a)(1), "each state shall . . . submit to the Administrator, within 3 years. . .after promulgation of a [primary NAAQS] (or any revision thereof) a plan which provides for implementation, maintenance, and enforcement of such primary standard. . ." CAA section 110(a)(2)(D)(i)(I) requires such SIPs to "contain adequate provisions prohibiting . . .any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will contribute significantly to nonattainment in, or interfere with maintenance by, and other State with respect to such NAAQS.

March 27, 2018 - EPA published a memo, entitled "Information on the Interstate Transport State Implementation Plan Submissions for the 2015 Ozone National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I)". EPA's Memo included new transport modeling data for the year 2023 (the Moderate Attainment deadline for the 2015 ozone NAAQS). These data are provided to assist states in completing the "good neighbor" SIPs for the 2015 ozone NAAQS, and to thereby address interstate transport obligations.

October 1, 2018 - Minnesota Pollution Control Agency (MPCA) submitted a SIP revision to address CAA Section 110(a)(2)(D)(i)(I) on October 1, 2018 .[73] The submission met the statutory deadline for submittal the interest transport SIPs for the 2015 ozone NAAQS. The submission utilized both EPA modeling released with the March 2018 memorandum and LADCO modeling results previously mentioned. Minnesota followed the 4-step interstate transport framework and used an analytic year of 2023 to describe Minnesota's lack of contributions to out of state receptors and assess emission reduction considerations.

April 1, 2019 – This is 6 months after EPA received the Minnesota SIP submission and is the date that the CAA deems the Minnesota submittal to have been complete since EPA did not take action otherwise.

September 13, 2019 - The D.C. Circuit issued a decision in *Wisconsin v. EPA*, remanding the CSAPR Update to the extent that it failed to require upwind states to eliminate their significant

[73] **Completeness Finding** - Pursuant to the CAA Section 110(k)(1)(B) "Within 60 days of the Administrator's receipt of a plan or plan revision, but no later than 6 months after the date, if any, by which a State is required to submit the plan or revision, the Administrator shall determine whether the minimum criteria established pursuant to subparagraph (A) have been met. Any plan or plan revision that a State submits to the Administrator, and that has not been determined by the Administrator (by the date 6 months after receipt of the submission) to have failed to meet the minimum criteria established pursuant to subparagraph (a), shall on that date be deemed by operation of law to meet such minimum criteria."

contribution by the next applicable attainment date by which downwind states must come into compliance with the NAAQS, as established under CAA section 181(a). 938 F.3d at 313.

April 1, 2020 – This is 12 months after the completeness date and is the deadline for EPA to have acted on the MN SIP submission. Upon this deadline a full, partial or conditional approval was required by CAA Section 110(k)(2), (3), or (4).[74]

May 19, 2020 - the D.C. Circuit issued a decision in *Maryland v. EPA* that cited the Wisconsin decision in holding that EPA must assess the impact of interstate transport on air quality at the next downwind attainment date, including Marginal area attainment dates, in evaluating the basis for EPA's denial of a petition under CAA section 126(b). Maryland v. EPA, 958 F.3d 1185, 1203-04 (D.C. Cir. 2020). The court noted that "section 126(b) incorporates the Good Neighbor Provision," and, therefore, "EPA must find a violation [of section 126] if an upwind source will significantly contribute to downwind nonattainment at the next downwind attainment deadline. Therefore, the agency must evaluate downwind air quality at that deadline, not at some later date." Id. at 1204 (emphasis added). EPA interprets the court's holding in Maryland as requiring the states and the Agency, under the good neighbor provision, to assess downwind air quality as expeditiously as practicable and no later than the next applicable attainment date, which is now the Moderate area attainment date under CAA section 181 for ozone nonattainment. The Moderate area attainment date for the 2015 ozone NAAQS is August 3, 2024. At the time of the statutory deadline to submit interstate transport SIPs (October 1, 2018), many states relied upon EPA modeling of the year 2023, and no state provided an alternative analysis using a 2021 analytic year (or the prior 2020 ozone season). However, EPA must act on SIP submittals using the information available at the time it takes such action. In this circumstance, EPA does not believe it would be appropriate to evaluate states' obligations under CAA section 110(a)(2)(D)(i)(I) as of an attainment date that is wholly in the past, because the Agency interprets the interstate transport provision as forward looking. See 86 FR at 23074; see also Wisconsin, 938 F.3d at 322. Consequently, in this proposal EPA will use the analytical year of 2023 to evaluate each state's CAA section 110(a)(2)(D)(i)(I) SIP submission with respect to the 2015 ozone NAAQS.

May 12, 2021 – Downwinders at Risk, et al filed Case No. 21 Civ. 21 Civ 3551 asserting that EPA failed to undertake certain non-discretionary duties under the CAA.

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[74] **Deadline for Action**. – Pursuant to the CAA Section 110(k)(1)(B) "Within 12 months of a determination by the Administrator (or a determination deemed by operation of law) under paragraph (1) that a State has submitted a plan or plan revision (or, in the Administrator's discretion, part thereof) that meets the minimum criteria established pursuant to paragraph (1), if applicable (or, if those criteria are not applicable, within 12 months of submission of the plan or revision), the Administrator shall act on the submission in accordance with paragraph (3)."

February 22, 2022 - EPA assessed the Minnesota submittal and on February 22, 2022 (3 years, 4+ months after submittal) the agency proposed denial of the Minnesota SIP as follows: "Based on EPA's evaluation of Minnesota's SIP submission and after consideration of updated EPA modeling using the 2016-based emissions modeling platform, EPA is proposing to find that the portion of Minnesota's October 1, 2018 SIP submission addressing CAA section 110(a)(2)(D)(i)(I) does not meet the state's interstate transport obligations for 2015 ozone NAAQS, because it fails to contain the necessary provisions to eliminate emissions that will contribute significantly to nonattainment or interfere with maintenance of the NAAQS in any other state. Air Plan Disapproval; Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin; Air Plan Disapproval; Region 5 Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 87 Fed. Reg. 9838 (Feb. 22, 2022).

February 28, 2022 – EPA and Downwinders et al established in a Consent Decree entered into on 1/12/2022 that if EPA proposed a full or partial denial of the Minnesota SIP EPA shall have until December 15, 2022 to sign a final action. Note this is a settlement and does not erase the fact that EPA failed to complete its non-discretionary duty to have reviewed and acted upon the MN SIP by April 1, 2020.

April 30, 2022 – EPA and Downwinders, et established in a Consent Decree entered into on 1/12/2022 that required EPA to sign for publication final rulemaking on April 30, 2022 to approve, disapprove, and conditionally approve the Minnesota SIP submissions for the 2015 ozone NAAQS.

May 22, 2022 – EPA proposed to approve most elements of the Minnesota October 1, 2018 submission intended to address all applicable infrastructure requirements for the 2015 NAAQS. (87 FR 31462).

July 29, 2022 – EPA approved most elements of the Minnesota October 1, 2018 SIP submission from Minnesota regarding infrastructure requirements for the 2015 ozone NAAQS. EPA did not act on the interstate transport requirements and visibility impairments requirements. (87 FR 45663).

December 8, 2022 – EPA and Downwinders et al filed a Joint Motion of Stipulated Extension of Consent Decree deadlines that provided the following schedule.

December 15, 2022 – Former agreed upon deadline by Downwinders for EPA to act on Minnesota SIP, but this deadline was moved by agreement to January 31, 2022.

January 31, 2023 - deadline to sign final action on Minnesota SIP pursuant to agreed upon extension of Downwinders Consent Decree.

February 13, 2023 – EPA publishes final disapproval of State Implementation Plan (SIP) submissions for 19 states, including Minnesota. Air Plan Disapprovals; Interstate Transport of Air Pollution for the 2015 8-Hour Ozone National Ambient Air Quality Standards, 88 FR 9336.

March 15, 2023 – EPA issues final federal Good Neighbor Plan for the 2015 ozone NAAQS (publication in the Federal Register is still pending).

Motion to Stay, *United States Steel Corporation v. EPA*, *et al.*, Case No. 23-1207 (D.C. Cir.)

Exhibit L

Declaration of Alexis Piscitelli in Support of United States Steel Corporation's Motion for Stay (Aug. 22, 2023)

IN THE UNITED STATES CIRCUIT COURT
FOR THE DISTRICT OF COLUMBIA CIRCUIT

UNITED STATES STEEL CORPORATION, Petitioner v. UNITED STATES EVIRONMENTAL PROTECTION AGENCY, and MICHAEL S. REGAN, Administrator, U.S. EPA, Respondents.	Case No. 23-1207 Consolidated with Case Nos. 23-1157 (lead), 23-1181, 23-1183, 23-1190, 23-1191, 23-1193, 23-1195, 23-1199, 23-1200, 23-1201, 23-1202, 23-1203, 23-1205, 23-1206, 23-1208, 23-1209, and 23-1211

Declaration of Alexis Piscitelli in Support of United States Steel Corporation's Motion for Stay

I, Alexis Piscitelli, am over 18 years of age and make the following declaration pursuant to 28 U.S.C. § 1746:

1. I am the Senior Director Environmental for North American Flat Roll. at United States Steel Corporation ("U. S. Steel"), where I am responsible for ensuring compliance and reporting requirements are met in accordance with federal, state and local environmental permits and regulations. I have been employed by U. S. Steel for over 26 years and have advanced through various positions.

2. I am providing this declaration on behalf of U. S. Steel's Motion for Stay of the United States Environmental Protection Agency's ("EPA's") Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality

Standards ("Good Neighbor Plan" or "Final Rule"), 88 Fed. Re. 36,654 (June 5, 2023).

3. As further explained in this declaration, the Final Rule will require immediate actions by U. S. Steel, including either curtailing the operation of reheat furnaces and boilers at U. S. Steel, or the expenditure of millions of dollars to prepare now for implementation of the Good Neighbor Plan. Either or both of these actions will impose significant additional cost on U. S. Steel. Curtailing or the potential shutdown of the reheat furnaces would impact downstream units and ultimately customers. Curtailing the boilers will reduce electricity generation and increase the demand for outside purchased power, increasing costs and putting additional strain on the grid.

4. The Good Neighbor Plan also omits important flexibilities U. S. Steel uses to effectively and efficiently manage its environmental obligations.

5. This declaration is based on my personal knowledge of facts and information pertaining to U. S. Steel's business and the implications of EPA's Good Neighbor Plan. My knowledge is based on my history with U. S. Steel and analysis U. S. Steel has conducted of the Good Neighbor Plan.

I. The Implementation Schedule for the Good Neighbor Plan is Insufficient

6. In response to the Good Neighbor Plan, U. S. Steel developed a schedule for compliance with the regulatory obligations applicable to U. S. Steel – Gary Works' 84" Hot Strip Mill.

7. Based on our experience with projects of similar size and complexity, the assessment, design, permitting, and installation of low-NOx burners at all four furnaces will not be complete until May 2027, over a year beyond the May 2026 deadline for certification of completion of installation of low-NOx technology in the Good Neighbor Plan. A copy of the project schedule is included as Appendix A to the attached Barr report (Attachment 1).

8. This schedule conservatively assumes that permitting can be completed in six months. Based on my experience, permitting can take significantly longer, leading to additional delays in completion.

9. U. S. Steel has also had difficulty obtaining vendor quotes for the required work. Consistent with U. S. Steel practice, our contractor, Barr, has attempted to obtain three separate vendor quotes for each technology U. S. Steel is analyzing. Only two firms provided full responses as of July 7, 2023. For one technology, selective non-catalytic reduction ("SNCR"), Barr contacted at least eight vendors but was able to obtain only two estimates. This further demonstrates the need for additional time for

implementation of the Good Neighbor Plan, as we anticipate vendors will continue to experience backlogs and supply chain disruptions.

10. U. S. Steel has also had difficulty finding and scheduling qualified union contractors to work on significant projects at our facilities. For example, there are four reheat furnaces at Gary, each will require a significant outage to retrofit the equipment with low NOx burners or the equivalent. We anticipate the availability of qualified union workers will become even a larger issue with multiple sources being impacted by the Good Neighbor Plan.

II. Implementation of the Good Neighbor Plan Requires U. S. Steel to Incur Immediate and Significant Costs

11. Among other things, the Good Neighbor Plan as promulgated imposes requirements on certain reheat furnaces at iron and steel mills, including the requirement to design a low-NOx burner or alternative low-NOx technology to achieve NOx emission reductions of at least 40% from baseline emission levels measured during performance testing that meets the criteria set forth in the rule. Additional obligations include emissions monitoring, recordkeeping, and reporting requirements.

12. While I agree that requiring a universal, hard limit for reheat furnaces is not appropriate, the requirement to design to meet a minimum 40% reduction of NOx from baseline is not appropriate because it does not take into account

what is achievable for each reheat furnace, including what the baseline value actually is – whether, for example, it is 0.12 lb/MMBtu or 0.24 lb/MMBtu, what limits there are on the type of NOx reduction technology that can be used, what fuels the reheat furnace uses, what other pollution control technologies are already in place, or other factors that may make a minimum 40% reduction on some units technically or economically infeasible.

13. Baseline emission level performance testing cannot be completed without significant modification. For example, the reheat furnaces at Gary are very difficult to access. Testing equipment required to meet the USEPA specification cannot be used as currently configured. The facility will require engineered modification to provide access for personnel and equipment to conduct the required testing to establish a baseline for at least a 40% reduction design.

14. Based on the deadlines in the Good Neighbor Plan, which include submitting a completed work plan by August 5, 2024, U. S. Steel has already needed to begin project engineering and design and is already incurring significant costs to complete this work. Without a stay, and while the rule is subject to petitions for review, these costs are expected to substantially

increase in the coming months with EPA's aggressive rule implementation schedule.

15. Based on an initial assessment of the costs supported by vendor quotes, I estimate installing low-NOx burners at the four reheat furnaces at U. S. Steel – Gary Works' 84" Hot Strip Mill will cost between approximately $28 million to more than $46 million. *See* Attachment 1 at Table 4-1. This does not include additional operating costs associated with the new equipment or additional monitoring, performance testing, recordkeeping, and reporting costs associated with the Good Neighbor Plan.

16. This results in an estimated cost effectiveness of between $18,300 and $42,300 per ton NOx removed. Attachment 1 at Table 4-2. This far exceeds $3,656/ton average EPA includes in its Technical Memorandum to support the Final Rule. Summary of Final Rule Applicability Criteria and Emissions Limits for Non-EGU Emissions Units, EPA-HQ-OAR-2021-0668-0956, at Table 6 (March 15, 2023). It also far exceeds EPA's marginal cost threshold of $7,500/ton, the average cost-per-ton range for all non-EGUs of $939/ton to $14,595/ton, and even the $11,000/ton representative EGU retrofit cost EPA used for comparison in the Good Neighbor Plan. Final Rule at 36,746.

17. Without the Good Neighbor Plan, U. S. Steel would not need to incur these costs.

18. To comply with the Good Neighbor Plan, U. S. Steel will need to take reheat furnaces and boilers offline while they are retrofitted. This will involve multiple outages that would be unnecessary without the Good Neighbor Plan. These outages will impact production capabilities and may lead to the flaring of by-product fuels, wasting a valuable resource.

19. A stay of the FIP is necessary to avoid these unnecessary costs and outages until a final decision is reached on what obligations should apply to reheat furnaces and boilers at iron and steel mills.

20. Without a stay, U. S. Steel will incur significant and irreparable harm in reconfiguring the hot strip mill at Gary Works to allow for baseline performance testing and implementing the rule's requirements at the Company.

III. **The Cumulative Burdens of the Good Neighbor Plan and Other Federal Requirements will Be Substantial and Could Have a Material Impact on Critical Infrastructure, National Security, and U. S. Steel Operations.**

21. The U.S. steel industry is responsible for over $520 billion in economic output, supporting over 2 million jobs. It generates over $56 billion in tax revenues annually.

22. In a study conducted under Section 232 of the Trade Expansion Act of 1962 (19 U.S.C. §1862), the U.S. Department of Commerce determined that domestic steel production is essential for national security; and that domestic

steel production depends on a healthy and competitive U.S. industry. (*See* https://www.bis.doc.gov/index.php/other-areas/office-of-technology-evaluation-ote/section-232-investigations).

23. The Cybersecurity & Infrastructure Security Agency has identified the iron and steel industry as a core critical infrastructure industry impacting transportation systems, electric power grid, water systems, and energy generation systems. (*See* https://www.cisa.gov/topics/critical-infrastructure-security-and-resilience/critical-infrastructure-sectors/critical-manufacturing-sector).

24. Implementation of the Final Rule upon the steel industry, when at the same time implementing new rules upon all facets of domestic steel manufacturing also potentially jeopardizes thousands of good-paying USW jobs.

25. U. S. Steel is committed to continuing to work with federal partners to develop and implement scientifically sound regulations that effectively and demonstrably benefit the environment.

26. EPA's promulgation of overlapping Clean Air Act regulations without adequate consideration of their interaction undermines these efforts.

27. At the same time that EPA promulgated the Good Neighbor Plan, where it is mandating the installation of controls at reheat furnaces and boilers at iron

and steel mills, EPA is proposing new MACT standards at taconite, integrated iron and steel facilities, and coke plants; as well as proposing revised NAAQS standards (e.g., PM2.5) which, combined, could have a material impact on the domestic steel industry, significantly affect the schedule for achieving these requirements, and result in a shortage of available technical support for implementation of these rules.

28. As noted above, U. S. Steel is already having difficulty obtaining qualified contractors and vendor quotes. These additional rules will exacerbate the problem.

29. EPA has also announced that it anticipates proposing reconsideration of the current ozone NAAQS in April 2024. As a result, EPA may be revising the ozone NAAQS at the same time that the Good Neighbor Plan is requiring U. S. Steel to install pollution controls to address the current standards. Piecemealing these two rules, for which implementation will likely overlap, is problematic and inappropriate, as U. S. Steel could quite possibly be compelled to install additional or different controls on the same emission units following EPA's reconsideration. This would result in significant waste and could be avoided if EPA withdraws the Good Neighbor Plan and takes the two years allowed by the Clean Air Act for implementation of a revised FIP.

IV. **Conclusion**

30. In my opinion, the schedule set forth in the Good Neighbor Plan is not realistic and underestimates the time needed for compliance by at least a year. If emission units cannot achieve compliance by the scheduled deadlines and the deadlines are not stayed or extended, those emission units will be required to curtail operation. As a result. U. S. Steel is already required to incur substantial costs in order to prepare for the upcoming Good Neighbor Plan deadlines despite pending petitions for reconsideration and judicial review that may affect the applicability of the Good Neighbor Plan and the obligations that it imposes on reheat furnaces and boilers.

31. A stay of the Good Neighbor Plan will mitigate these harms.

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on August 22, 2023.

Alexis Piscitelli
Sr. Director Environmental – NAFR
United States Steel Corporation