Appendix A: November 2022 Excerpted Chapters from Implementing EPA's Clean Power Plan: A Menu of Options

This document excepts chapters from the National Association of Clean Air Agencies' (NACAA) May 2015 guidance to its state and local members about options for complying with the U.S. EPA's 2016 proposed Clean Power Plan[1]. It is being submitted as an appendix to a November XX, 2022 Comment Letter from NACAA to EPA in response to Docket No. EPA-HQ-OAR-2022-0723, "Pre-Proposal Public Docket: Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants".

Chapters from the original document include:

Chapter	Title	Description
1	**Optimize Power Plant Operations**	Explores techniques to permit a plant to improve thermal efficiencies by up to four to seven percent, reducing coal combustion and GHG emissions by an equivalent quantity
2	**Implement Combined Heat and Power in the Electric Sector**	Focuses on combined heat and power at central electric generating units as a means of reducing the carbon emissions of the power sector
3	**Implement Combined Heat and Power in Other Sectors**	Discusses how combined heat and power technologies in the commercial, institutional, and manufacturing sectors can reduce CO_2 emissions across the economy through system-wide gains in energy efficiency that improve economic competitiveness
4	**Improve Coal Quality**	Discusses different coal types and beneficiation options, examples of different types of beneficiation in practice, and the resulting GHG and environmental impacts of such actions
7	**Pursue Carbon Capture and Utilization or Sequestration**	Describes the process of carbon capture and storage/utilization, updates the state of projects throughout the United States, and details the regulatory backdrop for this technology
8	**Retire Aging Power Plants**	Explores the various decision metrics that affect whether a unit is retired and provides examples of how retirement decisions have been carried out in select jurisdictions.
9	**Switch Fuels at Existing Power Plants**	Explores fuel switching as an emissions reduction option, and outlines three strategies to accomplish fuel switching

[1] The May 2015 original is online at https://www.4cleanair.org/wp-content/uploads/Documents/NACAA_Menu_of_Options_LR.pdf

1. Optimize Power Plant Operations

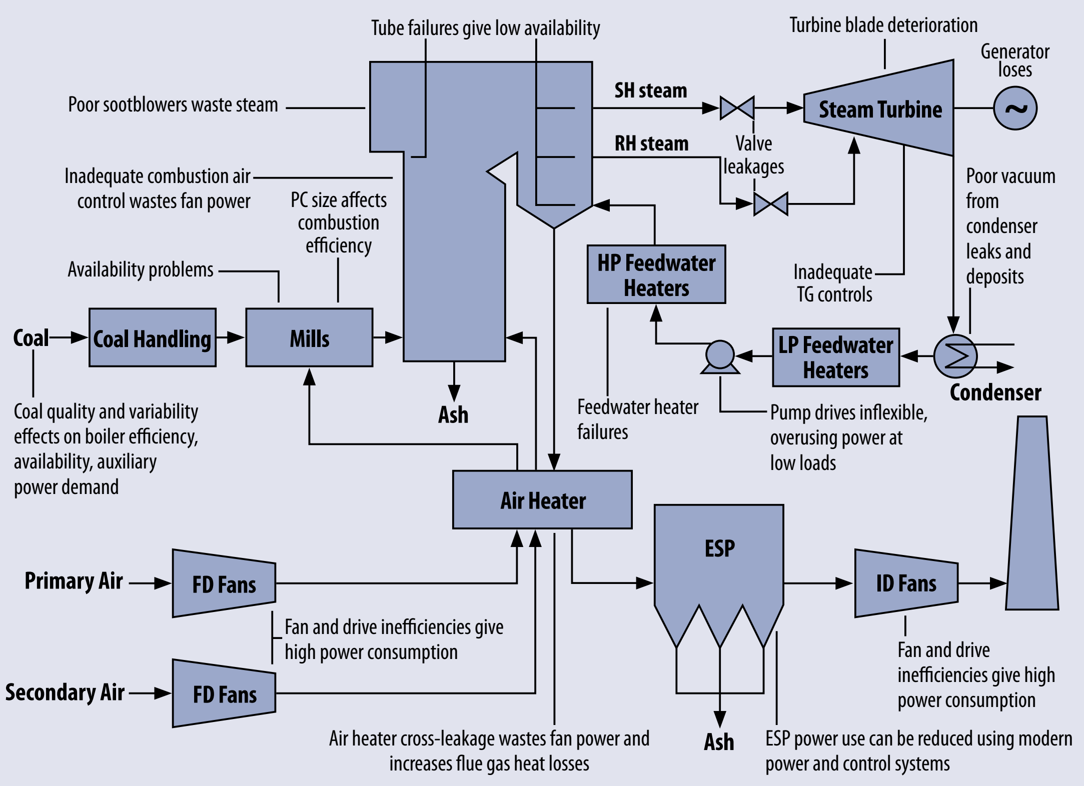
1. Profile

The average thermal efficiency of a coal-fired power plant in the United States across all classes of fuel is approximately 32 percent. This level has not changed in many years, as few new coal-fired power plants have been constructed in the last decade.[1] Figure 1-1 illustrates the various components of a power plant and factors that affect its thermal efficiency.

Operating experience reflects that the thermal efficiency of a power plant declines with use. Much of the efficiency degradation can be recovered during maintenance outages such that, over time, a unit's efficiency plotted versus time will have a sawtooth pattern. The level of maintenance undertaken will dictate the amount of efficiency loss that is recovered during each outage but, after a unit is 30 years old, even well-maintained equipment suffers from persistent degradation. Another contributing factor to the loss of efficiency over time is that older units are more likely to operate in a load-following mode, rather than a baseload mode, as newer units take their place

Figure 1-1

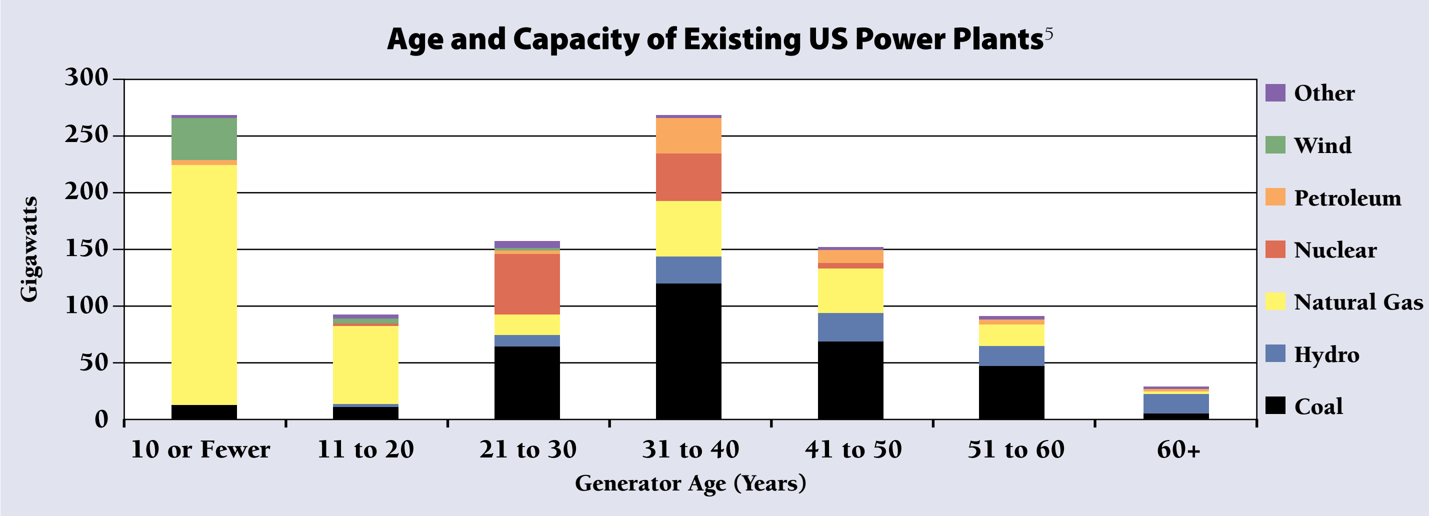
Areas of a Coal-Fired Power Plant That Give Rise to Efficiency Loss[2]



1 New coal-fired plants would not necessarily be more efficient than older coal-fired units. New units would be more likely to have high levels of emissions controls that increase the auxiliary load of the unit and reduce net output. New units may also have more restrictions on cooling water resulting in higher condenser pressure, and may be designed to operate flexibly rather than maximizing efficiency for one specific mode of operation. All of these factors would tend to have a negative impact on a unit's thermal efficiency.

2 Henderson, C. (2013, August). *Upgrading and Efficiency Improvement in Coal-Fired Power Plants.* International Energy Agency (IEA) Clean Coal Centre, CCC-221, ISBN 978-92-9029-541-9. Copies can be downloaded for free by member countries at: http://bookshop.iea-coal.org/publishor/system/component_viewbymedia.asp?logdocid=83186&MediaId=2. Registration required first.

Figure 1-2



in the dispatch order.[3] The increase in cycling that comes from following load can have a significant impact on overall operating efficiency. The thermal efficiency of an older plant can thus be significantly lower than that which existed at the time it commenced operation.[4] The average age of the US coal fleet is over 30 years, with up to one-third of the units over 50 years old in some regions. Figure 1-2 shows the ages of US fossil-fuel generation by ten-year increments, reflecting that approximately 500 gigawatts (GW) of total generation are produced by power plants that are 31 years old or older.

Using actual data from existing coal-fired power plants, the top ten percent of units have a thermal efficiency of 37.6 percent. This level is more than five percentage points higher than the average efficiency, and imputes a fuel consumption rate that is 15 percent lower than the average.[6] Table 1-1 breaks out unit level thermal efficiency by equal-weighted capacity deciles.[7] The table reflects that units with lower thermal efficiency have lower capacity factors, meaning that they operate for fewer hours in a given year, and that inefficient units are also smaller. Nearly 200 units comprise the least thermally efficient decile, whereas 53 units comprise the most thermally efficient decile. This profile suggests two key points: (1) inefficient units burn more fuel per megawatt hour (MWh) of generation and have higher fuel costs relative to other

3 "Baseload" generating units operate at fairly constant output levels near their maximum rated capacity, except when they are down for maintenance. These units tend to be the ones that are most thermally efficient or that have low operating costs for other reasons. "Load-following" generating units cycle their output levels up or down in response to a "dispatch" signal from a system operator, as needed to match total system-wide generation to the varying system-wide demand for electricity. Load-following units usually have higher operating costs than baseload units because they are less thermally efficient or for other reasons.

4 Boiler design is critical to the efficient operation of a power plant. Boiler design life is predicated on adherence to good fluid dynamics and heat transfer principles. Layout of the plant's ductwork and piping aims to minimize turns and bends and have large diameter ducts to minimize pressure drops, to maximize the thermal efficiency of the plant, and to avoid extra energy demand just to move flue gases from one point to another. Critical to this are well-mixed flue gases, which depend on adequate retention time in the combustion chamber to complete chemical reactions, achieve maximum heat transfer, and minimize the formation of air pollutants. Well-mixed flue gases also ensure that duct velocities are uniform from top to bottom and side-to-side. Doing so helps to assure that flue gas temperatures are as uniform as possible. Flue gas hot spots can cause duct deformation, and flue gas cold spots can cause corrosion if the temperatures drop below the acid dew point.

5 US Energy Information Administration (EIA). (2011, June 16). *Today in Energy.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

6 US Department of Energy (DOE). (2008, July). *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet*. National Energy Technology Laboratory (NETL), DOE/NETL-2008/1329. This report is no longer available online.

7 A decile is any one of nine numbers that divide a frequency distribution into 10 classes such that each contains the same number of individuals; also: any one of these 10 classes.

Table 1-1

Generation-Weighted Thermal Efficiency[9]

Decile	Number of Units	Capacity (GW)	Capacity Factor	2008 Total Generation (Billion kWh)[10]	2008 Generation-Weighted Efficiency (HHV)[11]
1	194	30.5	62%	165	27.6%
2	102	30.3	67%	179	29.9%
3	88	30.7	65%	176	30.8%
4	86	30.6	69%	185	31.6%
5	75	30.7	70%	189	32.2%
6	83	30.8	66%	178	32.9%
7	71	31.0	68%	186	33.8%
8	79	30.6	68%	183	34.7%
9	61	30.8	67%	181	35.7%
10	53	30.7	74%	201	37.6%
OVERALL	**892**	**307**	**69%**	**1823**	**32.5%**

units, and (2) less thermally efficient units operate more as peaking or cycling units.[8]

Onsite improvements to the power plant boiler and associated equipment can apply mature technologies and operating practices to reduce greenhouse gas (GHG) emissions by four to seven percent, on average. Older plants built between the 1950s and the 1970s have the greatest potential for improvement. Applications of these technologies also reduce fuel consumption, improve plant profitability, and reduce criteria pollutant emissions. Innovative new options have also been demonstrated that add onsite renewable generation to a coal-fired power plant site, further reducing GHG emissions by directly offsetting generation at the plant site or by using the renewable generation to help recover heat losses from the cooling system or flue gas.

The potential improvement that can be achieved by any given coal-fired generating unit will depend on at least three factors. First, some of the technologies and processes that improve thermal efficiency may be less feasible or effective owing to the design or operational requirements of the unit. For example, some of the possible improvements in steam turbine design will be less durable for units that operate with frequent start and stop cycles. Second, some units will have already implemented some of the available options and will have less room for improvement than an average unit. And third, the *capital* costs of improvement projects can be hard to recover through reduced *operating* costs for units that operate less frequently than an average unit. Nevertheless, there are many options to be considered.

This chapter explores a variety of boiler optimization technologies and processes, including those that:

- Optimize the combustion of coal;
- Recover waste heat from cooling systems;
- Recover waste heat from flue gases;

8 Very efficient units (e.g., supercritical units) require higher capital investments to build than less efficient units (e.g., subcritical units). The higher capital costs can be justified if the unit is expected to operate at a high capacity factor, whereas less efficient, less expensive designs make more sense when a unit is expected to operate at a lower capacity factor.

9 US DOE. (2010, February). *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States.* National Energy Technology Laboratory. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf.

10 One thousand kilowatt hours (kWh) is equal to one megawatt hour (MWh).

11 Higher Heating Value (HHV) is one of two common ways to express the amount of heat released when a given amount of fuel is combusted. This column shows the efficiency based on HHV values.

- Optimize soot blower operation;
- Improve turbine design;
- Use turbine inlet cooling (TIC) technologies for natural gas-fired power plants;
- Supplement coal-fired generation with onsite renewable generation; and
- Reduce auxiliary power consumption (i.e., the electricity used onsite to operate the power plant – sometimes referred to as "house load").[12]

Another option to improve boiler efficiency — better coal quality through drying or other beneficiation techniques — is covered separately in Chapter 4.

2. Regulatory Backdrop

The emphasis of this GHG reduction option is to improve the heat rate and thermal efficiency of the power plant through techniques that optimize the operation of the boiler or reduce heat losses from the flue gas and cooling systems, or to complete other techniques that reduce fuel consumption or auxiliary equipment energy consumption.

The US Department of Energy (DOE) National Energy Technology Laboratory (NETL) found consistent support among utilities for implementing onsite efficiency improvements, as there are direct financial benefits that accrue to the plant itself after such improvements have been completed. Lower fuel costs mean improved profit margins for the utility or plant operator. Improved thermal efficiency results in lower heat rates (less fuel burned per kilowatt hour (kWh) of generation), and also improves the ability of an individual unit to be dispatched by the electricity grid operator, which again can help improve the profitability of the particular unit.[13] NETL further found that the five boiler optimization options it considered in the cited study can be completed without requiring additional legislation or regulations. However, these kinds of changes at a power plant may require the owner/operator to obtain a new or modified air pollution permit. NETL found that uncertainty and risk associated with the permitting process has been a barrier to higher penetration of boiler optimization projects.

Hesitancy exists among air pollution regulators as well. Despite the fact that Prevention of Significant Deterioration regulations require the applicant and the permitting authority to assess energy, environmental, and economic factors to establish Best Available Control Technology (BACT) emissions limits, states and the US Environmental Protection Agency (EPA) have not always taken advantage of the expansive definition of BACT to encourage new or modified power plants to operate as efficiently (thermally) as possible. Standard practice has instead been to set a specific point source concentration-based emissions limit grounded in an assessment of the boiler type and fuel combusted, for example, X pounds of nitrogen oxides (NO_X) per million British thermal units (BTU[14]) or Y parts per million (ppm) of NO_X. A few states have made more concerted efforts to incorporate thermal efficiency considerations in BACT analyses. For example, an advisory board to the Virginia Department of Environmental Quality issued a report in 2011 that lays out a recommended process for that state to follow in determining BACT for GHG emissions.[15]

The EPA has more explicitly considered thermal efficiency in a number of rulemakings over the last decade. To begin with, the New Source Performance Standards for Electric Utility Steam Generating Units now include output-based emissions standards for particulate matter (PM), NO_X, and sulfur dioxide (SO_2) that are expressed as "pounds per MWh" limits. Most older federal regulations included input-based emissions standards only, for example, standards limiting the pounds of emissions per million BTUs (MMBTU) of energy input into a coal-fired boiler. Output-based emissions standards inherently promote thermal efficiency because it is easier

12 Waste heat recovery strategies are also featured in Chapters 2 and 3 of this document. Here in Chapter 1, the discussion of waste heat recovery is limited to the potential to capture heat that is produced at power plants as an inherent byproduct of generating electricity, and then using the captured heat onsite to improve the net heat rate of the generating unit. Other applications of waste heat recovery are considered in Chapters 2 and 3.

13 Supra footnote 6.

14 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Farenheit.

15 State Advisory Board on Air Pollution. (2011, November). Energy Efficiency Measures as Best Available Control Technology for Greenhouse Gases. Available at: http://www.deq.virginia.gov/Programs/Air/StateAdvisoryBoardonAirPollution/StateAdvisoryBoardReports.aspx.

to comply with a "pounds per MWh" standard if less fuel is combusted to generate each MWh. With input-based standards, an inefficient boiler that requires more fuel (more BTUs) to generate each MWh can legally emit more pounds of air pollutant per MWh.

In September 2013, the EPA released proposed New Source Performance Standards similarly limiting GHG emissions from new electric generating units. The proposed rule would set separate, output-based standards for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined-cycle units. It would require affected natural gas combined-cycle units to meet output-based standards of 1000 pounds of carbon dioxide (CO_2) per gross MWh (for units with a heat input rating of greater than 850 MMBTU per hour) or 1100 pounds of CO_2 per MWh (for units smaller than 850 MMBTU per hour). The corresponding standards for fossil fuel-fired boilers and integrated gasification combined- cycle units would be set at 1100 pounds of CO_2 per MWh over any 12-month period, or 1000 to 1050 pounds of CO_2 per MWh over an 84-month period.[16]

In addition to this new emphasis on output-based emissions standards, the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial Boilers rule that the EPA promulgated in 2012 requires affected facilities to complete energy assessments that produce "a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments." The Industrial Boiler NESHAP does not specifically require facilities to act on the recommendations in these assessment reports. This energy assessment concept was not replicated in the EPA's 2012 NESHAP for Coal and Oil-Fired Electric Utility Steam Generating Units (also known as the Mercury and Air Toxics Standards, or MATS), but the MATS rule does rely on output-based standards and those standards, according to the EPA, were developed after consideration of the potential for thermal efficiency projects to reduce emissions.

Boiler optimization techniques are also a central component of the emissions guidelines for GHG emissions from existing power plants that the EPA proposed on June 2, 2014 (a.k.a. the Clean Power Plan). The EPA determined that the "best system of emissions reduction" for this category of sources is one that consists of a combination of four "building blocks" determined to have been adequately demonstrated to reduce CO_2 emissions, with due consideration for impacts on the cost of electricity and electricity system reliability. The first of those four building blocks consists of practices that reduce the output-based emissions rate (pounds of CO_2 per net MWh) of affected power plants through heat rate improvements. The proposed emissions guidelines include a GHG reduction obligation for each state that is based in part on the EPA's analysis that heat rates of coal-fired power plants can be improved by six percent on average.[17] This rate of improvement is based on analysis conducted on a suite of hundreds of coal-fired power plants. The EPA acknowledges that individual plant heat rate improvements will differ; some may achieve greater than a six-percent improvement and some may achieve less, based on the individual characteristics at each plant.

This chapter focuses on the state of power plant efficiency today to provide support for states that want to evaluate how improved thermal efficiency can be part of a GHG emissions reduction plan. It is worth noting, however, that the engineering consulting firm Sargent & Lundy, in a 2009 report to the EPA, found that regulatory and economic barriers tilt the dynamics toward replacing the entire power plant, rather than overhauling and rebuilding equipment at existing plants.[18] This conclusion

16 The proposed standards for natural gas combined-cycle plants are equivalent to or less stringent than the limits noted in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for some recently issued permits, viz. Calpine Russell City Energy Center, California (1100 lb/MWh); Interstate Power and Light, Marshalltown, Iowa (951 lb/MWh); or Berks Hollow Energy Associates, Ontelaunee, Pennsylvania (1000 lb/MWh). The proposed standards for coal-fired plants, however, are premised on the implementation of at least partial carbon capture and storage and are about one-half the value of the CO_2 limit in the draft permit for the Wolverine Power Supply Cooperative, Michigan (2100 lb/MWh). Wolverine was the only coal-fired unit included in the EPA RBLC as of July 3, 2014.

17 US EPA. (2014, June 18). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating#h-72 at Section VI(B)(2).

18 Sargent & Lundy. (2009, January). *Coal-Fired Power Plant Heat Rate Reductions.* SL-009597. Available at: http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.

would appear to be at odds with the conclusions the EPA reached in its analysis for the Clean Power Plan, although it is not clear whether Sargent & Lundy would reach the same conclusions today that it reached in 2009. In any event, it will not be surprising if, in response to the Clean Power Plan, some operators choose to completely replace power plants while others opt for just a subset of the boiler optimization options described here.

3. State and Local Implementation Experiences

Evidence of the effectiveness of boiler optimization projects can be found in the previously cited NETL reports. A power plant in the western United States completed upgrades to its turbines and control system. Its average thermal efficiency improved from 32 to 35 percent. A power plant in the northeastern United States also completed upgrades to its turbines and improved the performance of its fan blades and pumps. Each of the three units at this plant improved thermal efficiency by three to eight percent.[19] Although these are but a few examples of projects already undertaken, NETL has found that obtaining comprehensive, detailed, and robust data is difficult, as many utilities consider the results of such projects to be confidential.[20]

Nevertheless, the International Energy Agency's (IEA) Clean Coal Centre, based in London, United Kingdom, published a report that includes several more case studies from the United States. The JH Campbell plant in Michigan converted from burning Eastern bituminous coal to a blend of 30-percent Powder River Basin (PRB) subbituminous and 70-percent Eastern bituminous coal. A comprehensive overhaul of plant equipment was completed to adjust to the lower-sulfur, higher-ash PRB coal. Steps taken included: additional overfire air ports, new furnace roof tubes, new superheater and economizer surfaces, new primary air heaters, and new primary air fans. Prior to the upgrade, plant NO_X emissions were 2.42 pounds per MWh. After the changes were completed, NO_X emissions were reduced to 1.01 pounds per MWh. The IEA case study did not include information about heat rate improvements at this plant.[22]

The Dairyland Power Cooperative JP Madgett plant in Alma, Wisconsin, undertook a turbine retrofit project in 2004. During the same time period as a major boiler maintenance project, the turbine unit was retrofitted with new blades and inner casing. As a result, the efficiencies of the high-pressure turbine increased by eight to ten percent, that of the intermediate pressure turbine by two to four percent, and overall output of the plant increased by 20 to 27 MW.

Installation of a continuous combustion management system at the Progress Energy Crystal River plant in Florida improved boiler efficiency by 0.5 percent and also reduced the fan energy requirements.[23]

Intelligent soot blowing systems were installed at the 780-MW Jeffrey Energy Center in St. Marys, Kansas, and the 574-MW Allen King Unit 1 in Bayport, Minnesota. Both plants burn PRB coal. The heat rate was improved by 0.87 percent at the Jeffrey plant and by 1.8 percent at the Allen King plant.[24] A neural network soot blower optimization system installed at the Big Bend Power Project in Texas reduced CO_2 emissions by 58,400 tons per year and NO_X by 3000 tons per year. The Deseret Power Bonanza Station in Utah installed neural network controls on its burners to improve boiler efficiency by one percent.[25]

TIC refers to a suite of technologies that can be used to cool the ambient air before it enters a natural gas-fired power plant's combustion chamber. Gas turbines operate at high thermal efficiency at an ambient temperature of 59 degrees Fahrenheit (F) and 60 percent relative humidity (so-called "standard conditions"). Thermal efficiency losses

19 DiPietro, P. (2009, November). *Improving Efficiency of Coal-Fired Power Plants for Near-Term CO_2 Reductions.* National Energy Technology Laboratory. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ImprovEfficCFPPNearTermCO2Reduct.pdf.

20 Supra footnote 9.

21 Supra footnote 3. Note that a second phase of the JH Campbell plant included a conversion to 100-percent PRB coal and installation of Selective Catalytic Reduction for additional NO_X reductions.

22 Supra footnote 2.

23 Ibid.

24 Ibid.

25 Asia-Pacific Economic Cooperation (APEC) Energy Working Group, Expert Group on Clean Fossil Energy. (2005, June). *Costs and Effectiveness of Upgrading and Refurbishing Older Coal-Fired Power Plants in Developing APEC Economies.* Energy Working Group Project EWG 04/2003T. Available at: http://www.egcfe.ewg.apec.org/Documents/Costs%26EffectivenessofUpgradingOlderCoal-FiredPowerPlantsFina.pdf.

Figure 1-3

Cameo Generating Station, Grand Junction, Colorado, with Parabolic Solar Trough Installation

Photo: Xcel Energy, Public Service of Colorado, 2011.

increase with increased ambient temperature. Compared to standard conditions, turbine power output declines by 7 percent at an ambient temperature of 25 degrees Celsius (C) (77 F), and declines by 15 percent at an ambient temperature of 36 C (97 F).[26] In many parts of the United States, peak electricity demand occurs during periods of hot weather, when air conditioning demand from homes and businesses rapidly increases. TIC technologies include chillers, wet compression, fogging, and evaporative cooling.[27]

Fewer data are available on the potential to supplement coal-fired generation with onsite renewable generation, but at least one demonstrated example exists. The Xcel Energy Cameo plant near Grand Junction, Colorado, shown in Figure 1-3, installed parabolic trough concentrating thermal solar technologies to provide supplemental heat to the coal-fired power plant's heat exchanger. The Xcel project was performed as part of a demonstration with the National Renewable Energy Laboratory to show the potential to combine renewable technologies with coal-fired plants to improve their thermal efficiency and to reduce GHG and criteria pollutant emissions. The project lasted one year (2010) and produced positive results. No coal unit outages were experienced. The coal-based heat rate declined by more than one percent. Coal savings were calculated to be 524,760 pounds for the one-year test period.[28]

4. GHG Emissions Reductions

If all types of boiler optimization projects are completed, plant operators can improve a plant's thermal efficiency in the range of four to seven percent. Because improved thermal efficiency means lower fuel or auxiliary power consumption, these translate into a similar range of GHG reductions at the plant site. Supplementing coal-fired generation with renewable generation can further reduce emissions. The EPA's Clean Power Plan analysis for heat rate improvement found that best operating practices can improve the heat rate of coal-fired power plants by four percent on average and, in addition, upgrades to equipment can improve heat rate by up to two percent.[29]

It should be noted that the prime purpose of boiler optimization projects completed in the United States has been to reduce fuel consumption and criteria pollutant emissions. Although GHG emissions are also reduced, this result has not been a primary objective to date; GHG emissions reductions have been a co-benefit of projects designed to reduce NO_X or SO_2 emissions. This may change with the promulgation of the EPA's Clean Power Plan guidelines for existing power plants, and future optimization projects will more likely seek to jointly and simultaneously reduce criteria, toxic, and GHG emissions.

Three recent reports describe projects to improve boiler efficiency. Data from DOE's NETL and from the Xcel Energy solar demonstration project are summarized in Table 1-2.

A subsequent 2014 research report by NETL also examined the effects of "off the shelf" technology options for coal pulverizer and combustion control improvement, condenser improvement, and steam turbine upgrades on

26 Chacartegui, R. (2008, August). *Analysis of Combustion Turbine Inlet Air Cooling Systems Applied to an Operating Cogeneration Power Plant.* Energy Conversion and Management, Volume 49, Issue 8, 2130–2141.

27 Turbine Inlet Cooling Association. (2014, June). *Technology Options to Increase Clean Electricity Production in Hot Weather.*

28 Xcel Energy, Public Service of Colorado. (2011, March). *Final Report: Innovative Clean Technology: "The Colorado Integrated Solar Project."* Docket No. 09A-015E. Available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/09A-015E%20Final%20CISP%20Report%20Final.pdf.

29 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602.

Table 1-2

Reported Efficiency Increase from Actual Efficiency Improvement Projects[30]		
Efficiency Improvement Technology	**Description**	**Reported Efficiency Increase**
Combustion Control Optimization	Combustion controls adjust coal and air flow to optimize steam production for the steam turbine/generator set. However, combustion control for a coal-fired EGU is complex and impacts a number of important operating parameters, including combustion efficiency, steam temperature, furnace slagging and fouling, and NO_X formation. The technologies include instruments that measure carbon levels in ash, coal flow rates, air flow rates, carbon monoxide levels, oxygen levels, slag deposits, and burner metrics as well as advanced coal nozzles and plasma-assisted coal combustion.	0.15% to 0.84%
Cooling System Heat Loss Recovery	Recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation through a cooling tower or discharge to a water body. The identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser.[31]	0.2% to 1%
Flue Gas Heat Recovery	Flue gas exit temperature from the air preheater can range from 250˚ F to 350˚ F, depending on the acid dew point temperature of the flue gas, which is dependent on the concentration of vapor phase sulfuric acid and moisture. For power plants equipped with wet flue gas desulfurization systems, the flue gas is further cooled to approximately 125˚ F as it is sprayed with the flue gas desulfurization reagent slurry. However, it may be possible to recover some of this lost energy in the flue gas to preheat boiler feedwater through the use of a condensing heat exchanger.	0.3% to 1.5%
Soot Blower Optimization	Soot blowers intermittently inject high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces in order to maintain adequate heat transfer.[32] Proper control of the timing and intensity of individual soot blowers is important to maintain steam temperature and boiler efficiency. The identified technologies include intelligent or neural-network soot blowing (i.e., soot blowing in response to real-time conditions in the boiler) and detonation soot blowing.	0.1% to 0.65%
Steam Turbine Design	There are recoverable energy losses that result from the mechanical design or physical condition of the steam turbine. For example, steam turbine manufacturers have improved the design of turbine blades and steam seals, which can increase both efficiency and output (i.e., steam turbine dense pack technology).[33]	0.84% to 2.6%
TIC	Several technologies can be used to cool inlet air during hot weather to increase the thermal efficiency of a natural gas combined cycle plant. These include: chillers, wet compression, fogging, and evaporative coolers.	8% to 26%[34]
Integrated Renewable Energy and Coal	Parabolic solar thermal troughs provide supplemental heat to the plant's heat exchanger to improve thermal efficiency.	1.33%

30 Data in this table for Turbine Inlet Cooling are from: Turbine Inlet Cooling Association. (2012, July). *Turbine Installation Data.* Available at: http://www.turbineinletcooling.org/data/ticadatap.pdf. Data for Integrated Renewable Energy and Coal are from: Xcel Energy, Public Service of Colorado. (2011, March). Final Report: Innovative Clean Technology: *"The Colorado Integrated Solar Project."* Docket No. 09A-015E. Available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/09A-015E%20Final%20CISP%20Report%20Final.pdf. All other data in this table are from: US DOE. (2008, July). *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet.* National Energy Technology Laboratory, DOE/NETL-2008/1329. The NETL study clarifies that reported efficiency improvement metrics are "adjusted to common basis by conversion methodology assuming individual component efficiencies for a reference plant as follows: 87 percent boiler efficiency, 40 percent turbine efficiency, 98 percent generator efficiency, and 6 percent auxiliary load. Based on these assumptions, the reference power plant has an overall efficiency of 32

two hypothetical coal-fired power plants. One of the hypothetical power plants was assumed to have a 1968-vintage, 550 MW unit with a heat rate of 10,559 BTU/kWh. The other hypothetical power plant also had a 550 MW unit, but was newer (1995-vintage) and more efficient (9,680 BTU/kWh heat rate). An emerging solar-assisted feedwater heating option was also evaluated.[35] NETL's 2014 report concluded that the "off the shelf" technologies could reduce CO_2 emissions at the two hypothetical power plants by 1.7 to 6.9 percent. Emissions at the retrofitted plants might be as little as one percent greater than the emissions expected from a new subcritical pulverized coal unit. In addition, the solar-assisted feedwater heating option could, by itself, potentially reduce CO_2 emissions 1.7 to 7.1 percent.

The IEA Clean Coal Centre report referenced earlier also provides data on the potential improvements in plant efficiency in several different areas, as shown in Table 1-3.

Sargent & Lundy's 2009 report to the EPA on possible projects to improve the heat rate at coal-fired power plants provides data based on small-, medium-, and large-sized electric generating units. These data, summarized in Table 1-4, represent a range based on Sargent & Lundy's industry surveys, discussions with equipment vendors, and review of operating experience at selected plants.[36]

For the data cited in Table 1-4, Sargent & Lundy used

Table 1-3

Potential Efficiency Improvements for Power Plants in the United States[37]

Area of Improvement	Efficiency increase, percentage points
Air heaters (optimise)	0.16–1.5
Ash removal system (replace)	0.1
Boiler (increase air heater surface)	2.1
Combustion system (optimise)	0.15–0.84
Condenser (optimise)	0.7–2.4
Cooling system performance (upgrade)	0.2–1
Feedwater heaters (optimise)	0.2–2
Flue gas moisture recovery	0.3–1.5
Flue gas heat recovery	0.3–1.5
Coal drying (installation)	0.1–1.7
Process controls (installation/improvement)	0.2–2
Reduction of slag and furnace fouling (magnesium hydroxide injection)	0.4
Soot blower optimisation	0.1–0.65
Steam leaks (reduce)	1.1
Steam turbine (refurbish)	0.84–2.6

percent and a net heat rate of 10,600 BTU/kWh. As a result, if a particular efficiency improvement method was reported to achieve a one-percent increase in boiler efficiency, it would be converted to a 0.37-percent increase in overall efficiency. Likewise, a reported 100-BTU/kWh decrease in net heat rate would be converted to a 0.30-percent increase in overall efficiency."

31 Replacing tower fill and tuning the tower and condenser improve the components' ability to reject heat to the atmosphere, thereby potentially reducing condenser backpressure and improving turbine thermal efficiency.

32 Soot blowers can also help clean the air preheater exchange surfaces.

33 Efficiency recovery from existing turbine components is also possible; this generally entails removing deposits from turbine blades, repairing damage to turbine blades, and straightening and sharpening packing teeth.

34 The reported data for turbine inlet cooling indicate the typical percentage power increase at specific plants. A few of the hundreds of power plants featured in the database reflect power increases greater or less than the range shown.

35 US DOE. (2014, April). *Options for Improving the Efficiency of Existing Coal-Fired Power Plants.* National Energy Technology Laboratory, DOE/NETL-2013/1611. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Efficiency-Upgrade-Final-Report.pdf.

36 Supra footnote 18.

37 Supra footnote 2.

Table 1-4

Potential Heat Rate Reductions (BTU/kWh) from System or Equipment Modifications for a Typical Coal-Fired Power Plant[38]

System or Equipment Modified	Power Plant Size 200 MW	500 MW	900 MW
Economizer	50–100	50–100	50–100
Neural Network	50–150	30–100	0–50
Intelligent Soot Blowers	30–150	30–90	30–90
Air Heater and Duct Leakage Control	10–40	10–40	10–40
Acid Dew Point Control	50–120	50–120	50–120
Turbine Overhaul	100–300	100–300	100–300
Condenser	30–70	30–70	30–70
Boiler Feed Pumps	25–50	25–50	25–50
Induced Draft (ID) Axial Fan and Motor	10–50	10–50	10–50
Variable Frequency Drives (VFD)	20–100	20–100	20–100
Combined VFD and Fan	10–150	10–150	10–150

an average boiler heat rate of 10,400 BTU/kWh. Although most of the above projects are discrete, the "combined VFD and fan" row represents a sum of the "ID axial fan" and the "VFD" projects. If all of the projects above were to be completed, and if all achieved the maximum possible heat rate improvement, thermal efficiencies could possibly be improved by more than ten percent. However, these data are based on discussions with equipment vendors. Sargent & Lundy was not able to exhaustively survey US coal-fired power plants and, like the NETL and IEA data cited earlier, was able to locate actual case examples for only a subset of the plant inventory.

5. Co-Benefits

In the examples described above, the prime purpose of boiler optimization projects was to reduce fuel consumption and criteria pollutant emissions. GHG reductions were a co-benefit of these projects. Boiler optimization projects, considered after EPA promulgates its Clean Power Plan emissions guidelines for existing power plants, are more likely to evaluate the benefits and compare tradeoffs between criteria, toxic, and GHG emissions.

The direct relationship between improved thermal efficiency and reduced fuel consumption reduces a plant's SO_2, NO_X, PM, and mercury emissions. Reductions in SO_2 and PM emissions will generally be proportional to the heat rate improvement, as the amount emitted is dictated by the sulfur and ash content of the fuel consumed. With NO_X emissions, nonlinear improvements are possible because most of the nitrogen comes from the combustion air rather than the fuel. For example, improvements in boiler efficiency achieved by replacing burners and installing new air supply can disproportionately reduce NO_X emissions. At a 550-MW plant, Siemens installed new burners and air supplies and saw NO_X emissions decrease from 1200 mg/m3 to 300 mg/m3. The plant also increased boiler efficiency by 0.42 percent and reduced fan power consumption by 900 kW.[39] The Deseret Power neural network controls reduced NO_X emissions by 20 percent and improved the plant's thermal efficiency by 1 percent, even with changes to different coals.[40]

The public health benefits associated with reductions in criteria and hazardous air pollutants are well documented across decades of published literature. In several recent rulemaking dockets, the EPA has consistently identified these co-benefits as constituting a substantial portion of the total benefits associated with reducing GHG emissions. For example, in the Regulatory Impact Analysis that the EPA published in conjunction with the Clean Power Plan proposal, air pollution health co-benefits represent more than half of the total calculated benefits under most of the analyzed scenarios.[41]

38 Supra footnote 18.

39 Supra footnote 2.

40 Supra footnote 25.

41 The EPA analyzed costs and benefits under a range of different assumptions. The results, summarized in Table ES-8 of the Regulatory Impact Analysis, show health benefits exceeding climate benefits in almost every scenario. Refer to: US EPA. (2014, June). *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants.* Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

Other types of co-benefits can also be significant. The full range of co-benefits that can be realized through boiler optimization are summarized in Table 1-5.

6. Costs and Cost-Effectiveness

It is difficult to make generalized statements about the cost of boiler optimization projects. Large utility-sized boilers are typically custom fabricated on a power plant site. The fuel handling system and boiler nozzles themselves are designed for particular fuel types. Coals – even within the same rank – have different properties, with varying heating values, ash content, and sulfur content. Also, the costs of many of the inputs used in boiler optimization projects, from copper wire and cement to the design and construction labor, can fluctuate significantly. Data confidentiality is often a further complication, as the cost of boiler optimization projects can be a sensitive topic. Consequently, much of the cost data cited herein comes from NETL, Sargent & Lundy, and the IEA Clean Coal Centre, and is based on generalized data from a broad range of coal-fired power plants. As a result, the cost data cited here should be interpreted as a guide or estimate only, and not strictly applicable to a particular future project.

Complete upgrades to a boiler to maximize efficiency improvement, including replacement of turbine blades, air preheaters, and all of the optimization tasks outlined in the IEA Clean Coal Centre report are estimated to range from $100 to $200 million.[42] However, boiler efficiency improvements of two to three percent can be achieved for a fraction of these costs through economizer, neural network, and intelligent soot blower projects.

Sargent & Lundy reflects that neural networks (artificial intelligence) have been installed at more than 300 US power plants. Boiler efficiencies have been improved by 0.3 to 0.9 percent, with an average improvement of 0.6 percent. Boilers using PRB coals have observed improvements of up to 1.5 percent. The average cost to install neural networks is $300,000 to $500,000, with annual operating costs of approximately $50,000.[43] Actual experience has shown that, in order to sustain the improved levels of thermal efficiencies over the long-term, various equipment that was previously manually controlled or adjusted, such as actuators, must be controlled by instruments and routinely maintained.[44]

The Allen King Plant reported a payback period of less than six months to recover costs from the improved soot blowing system.[45] At the Big Bend example referenced earlier, the upgraded soot blowing system cost $3 million and produced annual cost savings of $908,000, resulting in a payback period of slightly more than three years.[46] The

Table 1-5

Types of Co-Benefits Potentially Associated With Boiler Operation

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_X	Yes
SO_2	Yes
PM	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Maybe
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	No
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Maybe
Other	

42 Supra footnote 2.

43 Supra footnote 18.

44 Personal communication, James Staudt, April 2014.

45 Supra footnote 2.

46 Supra footnote 25.

heat rate at this plant was improved by 0.1 to 0.4 percent.[47]

The APEC Energy Working Group report, from which some of the case examples described here have been extracted, provides methodologies to assess the costs and benefits of various types of boiler optimization projects. Sample spreadsheets include default assumptions for unit level data on operating and capital costs and electricity revenues. Results are provided in terms of increased electricity revenue, reductions in fuel and ash costs, and emissions reductions.[48]

Table 1-6

Capital, Fixed O&M, and Variable O&M Costs of Boiler Optimization Projects[49]

System or Equipment Modified	Cost Item	Power Plant Size 200 MW	500 MW	900 MW
Economizer	Capital ($ million)	2–3	4–5	7–8
	Fixed O&M ($/yr)	50,000	100,000	150,000
	Variable O&M ($/yr)	0	0	0
Neural Network	Capital ($ million)	0.5	0.75	0.75
	Fixed O&M ($/yr)	50,000	50,000	50,000
	Variable O&M ($/yr)	0	0	0
Intelligent Soot Blowers	Capital ($ million)	0.3	0.5	0.5
	Fixed O&M ($/yr)	50,000	50,000	50,000
	Variable O&M ($/yr)	0	0	0
Air Heater and Duct Leakage Control	Capital ($ million)	0.3–0.5	0.6–0.7	1–1.2
	Fixed O&M ($/yr)	50,000	75,000	100,000
	Variable O&M ($/yr)	0	0	0
Acid Dew Point Control	Capital ($ million)	1.5–3.5	2.5–10.0	3.5–18
	Fixed O&M ($/yr)	50,000	75,000	100,000
	Variable O&M ($/yr)	170,000–350,000	425,000–850,000	750,000–1,500,000
Turbine Overhaul	Capital ($ million)	2–12	4–20	5–25
	Fixed O&M ($/yr)	0	0	0
	Variable O&M ($/yr)	0	0	0
Condenser	Capital ($ million)	0	0	0
	Fixed O&M ($/yr)	30,000	60,000	80,000
	Variable O&M ($/yr)	0	0	0
Boiler Feed Pumps	Capital ($ million)	0.25–0.35	0.5–0.6	0.7–0.8
	Fixed O&M ($/yr)	0	0	0
	Variable O&M ($/yr)	0	0	0
Induced Draft (ID) Axial Fan and Motor	Capital ($ million)	6–6.5	9–11	15–16
	Fixed O&M ($/yr)	50,000	85,000	130,000
	Variable O&M ($/yr)	0	0	0
Variable Frequency Drives (VFD)	Capital ($ million)	1.5–2	3–4	5–6
	Fixed O&M ($/yr)	20,000	30,000	50,000
	Variable O&M ($/yr)	0	0	0
Combined VFD and Fan	Capital ($ million)	6–6.5	9–11	15–16
	Fixed O&M ($/yr)	25,000	38,000	60,000
	Variable O&M ($/yr)	0	0	0

47 US DOE. (2007, September). *Clean Coal Technology: Power Plant Optimization Demonstration Projects.* Topical Report Number 25. Available at: http://www.netl.doe.gov/File%20Library/Research/Coal/major%20demonstrations/ppii/topical25.pdf.

48 Supra footnote 25. Detailed examples are provided in Chapter 8 of this report.

49 Supra footnote 18.

Reduct, a consultancy focusing on improved utility boiler performance, indicates that their experience, based on a study of approximately 1150 power plants in North America, reflects that a one- to three-percent improvement in boiler efficiency can be achieved at savings equal to $600,000 to $1,700,000 for a 450-MW power plant.[50]

Sargent & Lundy also assessed the capital costs, fixed operations and maintenance (O&M) costs, and variable O&M costs associated with the boiler optimization projects identified in Table 1-4. These cost data are shown in Table 1-6.[51]

Finally, the previously cited 2014 NETL report examined the costs of efficiency retrofits and compared those to the cost of building a new power plant.[52] The combined retrofit cost for the "off the shelf" technologies studied in that report was found to be just over $36 million dollars, or $66/kW, for each of the two hypothetical power plants. Considering both the capital cost and the O&M costs, NETL concluded that the cost of electricity at each power plant could increase by nearly 1 percent in the worst case, or decrease by as much as 3.5 percent. But perhaps more importantly, NETL also determined that the cost of electricity that results from deploying these technologies at either the older or the newer hypothetical power plant is 22 to 25 percent below the cost of building and operating a new, subcritical pulverized coal unit. According to NETL, "This could be a strong incentive for performing efficiency upgrades at coal units, as a strategy for reducing CO_2 emissions from the existing power generation fleet."

Costs for TIC technology installed as retrofits to existing natural gas combined cycle plants range from $30/kW for wetted media to $375/kW for chillers. The Turbine Inlet Cooling Association estimates a cost of $28.1 million to install chillers at a 500-MW gas-fired power plant. The chillers are estimated to increase the capacity of the plant by 75 MW during periods of the highest ambient temperatures.[53]

7. Other Considerations

Improving the heat rate reduces fuel consumption and a plant's operating costs. Although improved profitability might be an incentive to significantly improve a plant's thermal efficiency, depending on the degree of changes made and their effects on emissions a plant may be subject to New Source Review permitting requirements, including BACT review. In some cases, the BACT process can stretch out for months, especially if the state does not receive a complete permit application from the source. If emissions decrease, as is typically the case shown with the examples provided in this chapter, then any changes to the boiler and associated equipment may only require adjustments to the plant's operating permit or may be considered a minor modification. The plant owner or operator would of course consult with the appropriate permitting authority before undertaking any significant changes to the plant. In states with vertically integrated utilities, the owner would also consult with the state public service commission to determine if any of the expenses associated with the improved thermal efficiency projects could be recovered through appropriate rate-making or cost-recovery proceedings under the Commission jurisdiction.

Although permitting issues can present challenges, reducing fuel costs and improving the dispatch ability of the plant are well understood by plant owners and operators as reasons to consider these techniques. Even a one-percent improvement in thermal efficiency can change the order in which a plant is dispatched by the regional transmission operator. Improved heat rates relative to other generating units reorder the dispatch stack; the unit that has upgraded its boiler has a higher probability of running, and can increase its capacity factor and its profitability.

Improved thermal efficiency also means less discharge to water and solid waste streams. Less coal burned per MWh of generation means less ash generation. The life of the associated emissions control equipment can also be extended, with less corrosion and fouling.

50 Reduct and Lobbe Technologies, British Columbia. More information at http://www.reduct.com.

51 Supra footnote 18.

52 Supra footnote 35.

53 Turbine Inlet Cooling Association. (2014, June). *FAQ About Turbine Inlet Cooling Technologies.* Note that the 500 MW plant in the example above would *not* have a peak capacity of 500 MW at an ambient temperature of 100 F. It is more likely that the capacity would be in the 400-425 MW range (reflecting a 15-20% loss of capacity), and that the TIC technologies would be one way to restore the capacity lost by natural gas combined-cycle plants during high ambient temperature conditions.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on boiler optimization:

- Campbell, R. (2013, December). *Increasing the Efficiency of Existing Coal-Fired Power Plants.* Congressional Research Service. Available at: http://www.fas.org/sgp/crs/misc/R43343.pdf.
- Henderson, C. (2013, August). *Upgrading and Efficiency Improvement in Coal-Fired Power Plants.* International Energy Agency (IEA) Clean Coal Centre, CCC-221, ISBN 978-92-9029-541-9.
- Sargent & Lundy. (2009, January). *Coal-Fired Power Plant Heat Rate Reductions.* SL-009597. Available at: http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.
- Storm, R., & Reilly, T. (1987). *Coal-Fired Boiler Performance Improvement Through Combustion Optimization.* Prepared for American Society of Mechanical Engineers. Available at: http://www.stormeng.com/pdf/Coal%20Fired%20Boiler%20Performance%20Improvement%20Through%20Combustion%20Optimization.pdf.
- US DOE. (2008, July). *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet.* National Energy Technology Laboratory, DOE/NETL-2008/1329. This report is no longer available online.
- US DOE. (2012, January). *Improve Your Boiler's Combustion Efficiency.* Advanced Manufacturing Office. Available at: http://www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/steam4_boiler_efficiency.pdf.
- US DOE. (2014, April). *Options for Improving the Efficiency of Existing Coal-Fired Power Plants.* National Energy Technology Laboratory, DOE/NETL-2013/1611. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Efficiency-Upgrade-Final-Report.pdf.
- Doyle, B. W. (2003, June). *Combustion Source Evaluation Student Manual.* Air Pollution Training Institute, Course 427, Third Edition. Available at: http://www.4cleanair.org/APTI/427combined.pdf.
- US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

9. Summary

Boiler optimization and improved thermal efficiency are standard procedures that have been used for many decades. The recent development and maturity of artificial intelligence and neural networks to automatically adjust key variables and parameters de-emphasizes the role of human intervention, and helps to assure that the boiler performs at optimal efficiency levels at all times. Electricity load growth in the United States is at a steady one percent per year, and is expected by the Energy Information Administration to remain at those levels through 2040.[54] Energy efficiency continues to be the most cost-effective means to procure additional resources to meet electricity load growth. Thus there are few opportunities in the United States to construct new coal-fired power plants that achieve the thermal efficiency levels observed in China at their supercritical and ultra-supercritical power plants (up to 44- to 47-percent thermal efficiency, effectively combusting up to 50 percent less coal per MWh than the typical 32-percent thermal efficiency American plant). As a result, boiler optimization efforts in the United States must necessarily focus on ways to get the most generation (MWh) possible from each ton of coal combusted. The techniques described here will permit a plant to improve thermal efficiencies by up to four to seven percent, reducing coal combustion and GHG emissions by an equivalent quantity. Such techniques offer co-benefits in the form of lower criteria pollutant emissions, especially for NO_X and $PM_{2.5}$. Compared to previous performance at the same plant, reduced water and land discharges also result from improved efficiency. The interesting Colorado solar integration project showcases possibilities to achieve additional onsite efficiency improvements by using renewable technologies that provide supplemental heat to a plant heat exchanger.

54 US EIA. (2014, May). *Annual Energy Outlook 2014 – Market Trends: Electricity Demand.* Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm.

2. Implement Combined Heat and Power in the Electric Sector

1. Profile

One strategy for reducing carbon dioxide (CO_2) emissions is to capture the waste heat from electric generating units (EGUs) as a secondary output to serve other purposes, typically central heating and cooling or industrial processes in neighboring facilities. As described in the context of boiler optimization in Chapter 1, heat losses can be recovered from the flue gases or cooling system to improve plant efficiency (see Table 1-2). In addition to using waste heat to preheat boiler feedwater and meet other operational thermal requirements, plants can also capture and pipe heat locally to satisfy other co-located demand for thermal energy. Combined heat and power (CHP), also known as *cogeneration*, is the term used to describe this variety of technology configurations that sequentially generates both electric and useful thermal output from a single fuel source.

Generating only electricity, the average US coal-fired power plant has a conversion efficiency of 33 percent, which means that two-thirds of the energy input is lost through heat, largely in the condensation of steam.[1] CHP captures much of this waste heat as useful thermal output, substituting for heat that would have been produced separately.[2] Whereas generating electricity and thermal energy separately might have an overall efficiency ranging from 40 to 55 percent, CHP applications can achieve system efficiencies of 60 to 80 percent (Figure 2-1). These efficiency gains are accompanied by fuel savings that make CHP a cost-effective and commercially available solution for reducing CO_2 emissions. CHP both improves businesses' bottom lines and delivers system-wide benefits like reduced air pollution, improved grid reliability, and avoided electric losses on transmission and distribution networks. With CHP currently accounting for 8 percent of US generating capacity and 12 percent of electricity,[3] it is regarded as a widely underutilized opportunity for emissions reductions.[4] The US Department of Energy (DOE) has estimated that increasing CHP to 20 percent of electric power capacity by 2030 would reduce CO_2 emissions by more than 800 million metric tons per year.[5]

However, because the benefits of CHP accrue economy-wide and not just in the electric power sector, adequately

1 US Energy Information Administration. (2012). *Electric Power Annual Report, Table 8.1. Average Operating Heat Rate for Selected Energy Sources.* Available at: http://www.eia.gov/electricity/annual/html/epa_08_01.html

2 Note that because the heat needs to be extracted at a higher temperature and pressure than the large thermal loss in the condensers, recovering this heat from a power plant typically results in losses in power capacity. This is discussed in greater detail below.

3 Total US CHP capacity was 83 gigawatts in 2014. ICF International for the US DOE and Oak Ridge National Laboratory. (2014, March). *CHP Installation Database.* Available at: http://www.eea-inc.com/chpdata/

4 CHP can be said to be underutilized in the US market in comparison to high penetration rates in Europe. For example, CHP accounts for over 45 percent of electricity in Denmark and over 30 percent in the Netherlands (2009). CHP can also be regarded as underutilized on the basis that cost-effective investment opportunities are widely available. Assessments of economic feasibility are discussed below, but estimates typically range between 40 and 50 gigawatts of potential. See: European Environment Agency. (2012, April). *Combined Heat and Power Assessment: ENER 020.* Available at: http://www.eea.europa.eu/data-and-maps/indicators/combined-heat-and-power-chp-1/combined-heat-and-power-chp-2; McKinsey & Company. (2009). *Unlocking Energy Efficiency in the US Economy.* Available at: http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy; US DOE. (2008, December 1). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf

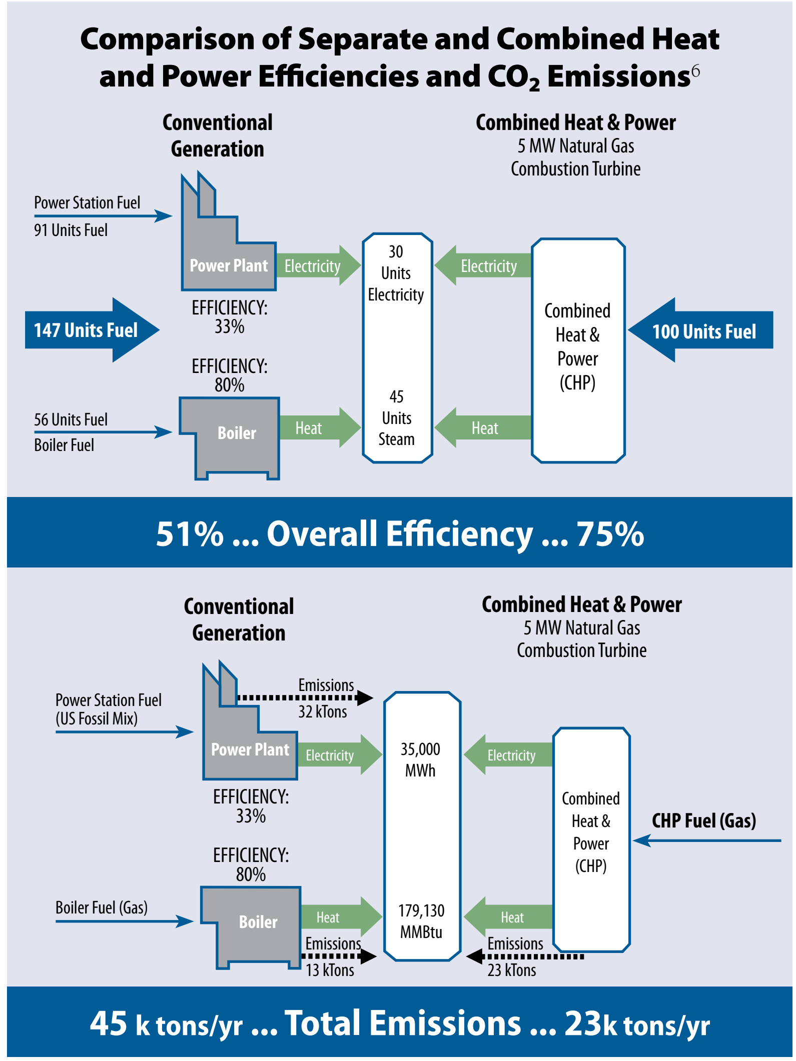
5 US DOE, at supra footnote 4.

accounting for them poses challenges. Modifying a generating unit to optimize for electric and thermal output, for example, improves overall energy utilization, but could result in an increase in the facility's direct emissions and an increase in emissions per unit of electric output. Therefore, although the technology is mature and although the emissions reduction potential is large, tapping that potential requires specialized accounting conventions and other carefully constructed regulatory, legal, and financial approaches that look at the total useful energy output of CHP (electric and thermal) and that look at impacts beyond the source of emissions.

Proposed federal regulations for greenhouse gas (GHG) emissions under sections 111(b) and 111(d) of the Clean Air Act are structured to create broad exemptions for CHP facilities. They affect only a portion of the existing CHP units in the power sector, larger units designed to deliver electricity to the grid (criteria provided in Section 2). For those units that are affected, the rules stipulate an accounting method that grants credit for a facility's useful thermal output and avoided line losses as a means of rewarding the environmental benefits of CHP (see Section 4). For other affected EGUs, the viability of retrofitting for CHP would be contingent on site-specific factors, such as plant equipment, local demand for thermal energy, fuel costs, market conditions, and so on, but retrofitting would also allow an EGU to claim the thermal and avoided line loss credits to improve its CO_2 emissions rate toward compliance. Alternatively, retrofitting could provide an opportunity for a unit to qualify for exemption. States could also use the energy efficiency or clean energy building blocks of the US Environmental Protection Agency's (EPA) Best System of Emission Reduction framework to incorporate CHP as a GHG abatement strategy, especially those installations that are exempt from EPA rules, both in and outside the power sector.

There are two basic types of CHP: *topping* and *bottoming* systems. In a "bottoming-cycle" configuration, also known as *waste heat to power,* the primary function is to combust fuel to provide thermal input to an industrial process, such as in a steel mill, cement kiln, or refinery. Waste heat is then recovered from the hot process exhaust for power generation, usually through a heat recovery boiler that makes high pressure steam to drive a turbine generator. More common is a "topping-cycle" system, a configuration

Figure 2-1



in which a steam turbine, gas turbine, or reciprocating engine has the primary purpose of generating electricity. Heat is then captured, usually as steam, and directed to nearby facilities, where it can be used to meet co-located demand for central heating or manufacturing processes. This chapter discusses topping-cycle CHP applications at central station EGUs as a means of reducing the carbon intensity of the electric power sector. Alternatively, CHP can be distributed across the electric grid at individual facilities, where energy users such as institutional, commercial, and manufacturing facilities have both power and heating or

6 US EPA. (2014, August). *CHP Partnership.* Available at: http://www.epa.gov/chp/. A power plant efficiency of 33 percent (higher heating value) denotes an average delivered efficiency based on 2009 data from eGRID for all fossil fuel power plants (35.6 percent), plus 7 percent transmission and distribution losses.

Table 2-1

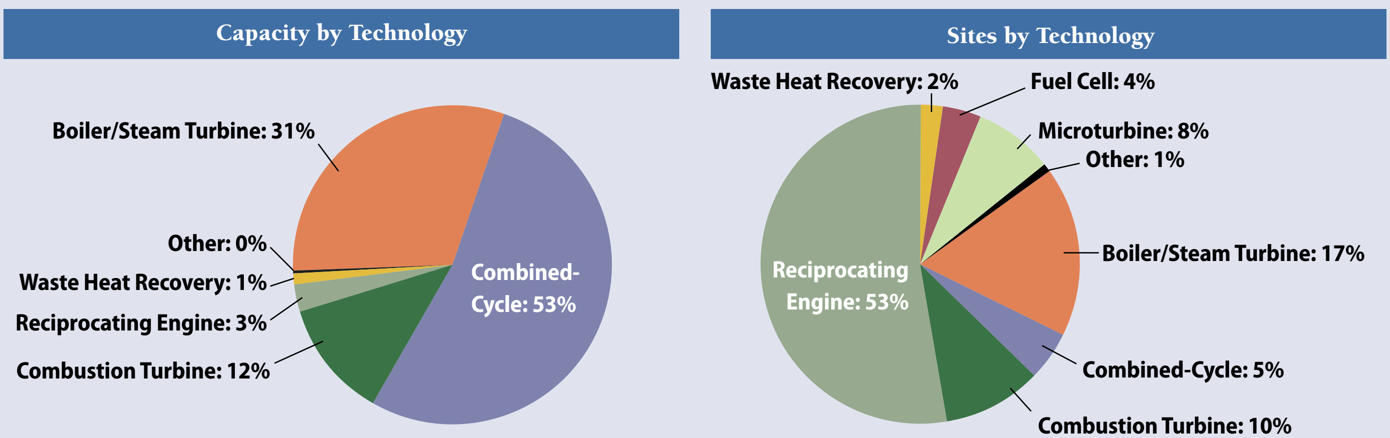
Summary of CHP Technologies for Large-Scale Applications[7]

CHP System Type	Advantages	Disadvantages	Available Sizes	Overall Efficiency (Higher Heating Value)	Installed, 2014 (Capacity/ Sites)[8]
Gas Turbine	High reliability Low emissions High-grade heat available Less cooling required	Requires high pressure gas or in-house gas compressor Poor efficiency at low loading Output falls as ambient temperature rises	500 kW to 300 MW	66% to 71%	64%/16%
Steam Turbine	High overall efficiency Any type of fuel can be used Ability to meet more than one site heat grade requirement Long working life and high reliability Power to heat ratio can be varied within a range	Slow startup Low power-to-heat ratio	50 kW to 300+ MW	Near 80%	32%/17%

kW - kilowatt
MW-megawatt

Figure 2-2

Existing US CHP Technology by Capacity and Site Number[9]



cooling requirements. Potential applications of this kind are more abundant than for large centralized CHP generating units, and are considered a specific type of distributed generation. CHP as a form of distributed generation is the subject of Chapter 3.

CHP can be based on a variety of different technology classes, including gas turbines, steam turbines, reciprocating engines, microturbines, and fuel cells. Of these, steam and gas turbines are the technologies that are most relevant to large capacity applications (25 megawatts [MW] to 300 MW), such as those that are typical in the electric sector. These technologies are summarized in Table 2-1.

As illustrated in Figure 2-2, these technologies comprise

7 US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies.* Tables II & III. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf. Note that CHP efficiency varies with size and power-to-heat ratio. These are illustrative values intended to represent typical CHP systems.

8 The data in the last column indicate each system type's percentage of total installed US CHP capacity (83.3 gigawatts) and total number of installations (4220 sites) as of 2014. Supra footnote 3.

9 ICF International for US DOE at supra footnote 3. Combined-cycle turbines (5 percent of all CHP installations), combustion turbines (10 percent), and steam turbines (17 percent) contribute disproportionately to total installed CHP capacity, collectively accounting for 97 percent of the total 83 gigawatts.

96 percent of all US installed CHP capacity, but account for only 33 percent of CHP sites, reflecting the large capacity of installations in these technology categories.

Whether the boiler is fueled by coal, biomass, solid waste, or other energy source, steam turbine applications are the most well established of utility-scale EGU technologies. CHP can be adapted as a retrofit to steam turbine power plants to capture heat that would otherwise exit the system through the cooling water. The cooling water itself, however, is usually not hot enough for district or process heating purposes. Therefore, depending on the thermal requirements, energy must be extracted farther upstream in the thermodynamic cycle, usually from the turbine, before the pressure and temperature are dropped to condense the steam.[10] This modification to the plant will result in reduced electrical output, although the overall energy utilization (electricity and useful thermal) is greater than would be the case if power and heat were produced separately. Because steam turbines are expensive to operate and generally have long startup times, the economics of a steam generator CHP are often more favorable for medium- to large-scale facilities outside the electric sector, such as chemical plants and primary metal processing plants with high capacity factors. However, the economics of CHP may be favorable at steam generator EGUs that are expected to operate with high capacity factors.[11]

CHP can also be applied to combustion turbine generation, whether burning natural gas, synthetic gas, or another gaseous fuel, in both simple-cycle and combined-cycle natural gas power plants. Natural gas is the most common fuel in CHP applications, accounting for more than 70 percent of capacity in the United States,[12] and although simple-cycle gas turbine CHP is often used in smaller installations (<40 MW), roughly half of the total US capacity is built around large, combined-cycle gas turbines that primarily generate electric output for the grid while also supplying steam to neighboring facilities.

In simple-cycle plants, fuel is combusted to generate electricity by heating and compressing air, the resulting force of which drives the power turbine. The exhaust gas leaving the turbine is very hot, between 800° and 1100° Fahrenheit, depending on the type of unit. In simple-cycle CHP applications, the exhaust gas directly serves as a source of process energy or, more likely, it is run through a heat exchanger, typically a heat recovery steam generator, after which steam serves as the energy carrier for thermal purposes. Although simple-cycle gas turbines have an electric efficiency ranging from 15 to 42 percent, simple-cycle CHP units usually achieve 65 to 70 percent.[13]

A combined-cycle turbine (see Figure 2-3) runs high temperature exhaust through a waste heat recovery unit to produce steam for a second cycle of power generation based on a steam turbine. This configuration has an electric efficiency ranging from 38 to 60 percent. CHP applications to this configuration will usually extract mid- to high-pressure steam before the steam turbine, or low pressure steam after the steam turbine, depending on the required performance specifications of the thermal user. In this way, combined-cycle CHP can achieve system efficiencies of 60 to 70 percent.

Achieving high rates of efficiency depends on having a dedicated thermal load that is compatible in size with the thermal output of the CHP system. A CHP system sited at a commercial or industrial facility will usually be sized and designed to accommodate the thermal demand, but for retrofits to existing power plants, optimizing the CHP system in this way is not an option. Instead, the design objective for EGU retrofits would require balancing the tradeoff between thermal energy sales and reduced power production on steam turbines. In practice, achieving this

10 There are two kinds of steam turbine CHP. In a *non-condensing* or *back-pressure system*, the flow of steam exiting the turbine is fed entirely to the process requirements, usually at low to medium pressure. In an *extraction* turbine, higher pressure steam is extracted through openings in the turbine casing, while the rest of the steam continues its expansion in the turbine to be exhausted into the condenser. An extraction turbine may be designed to allow for regulation of heat-to-power ratio and for extraction of steam at different pressure levels. For more, see: supra footnote 7.

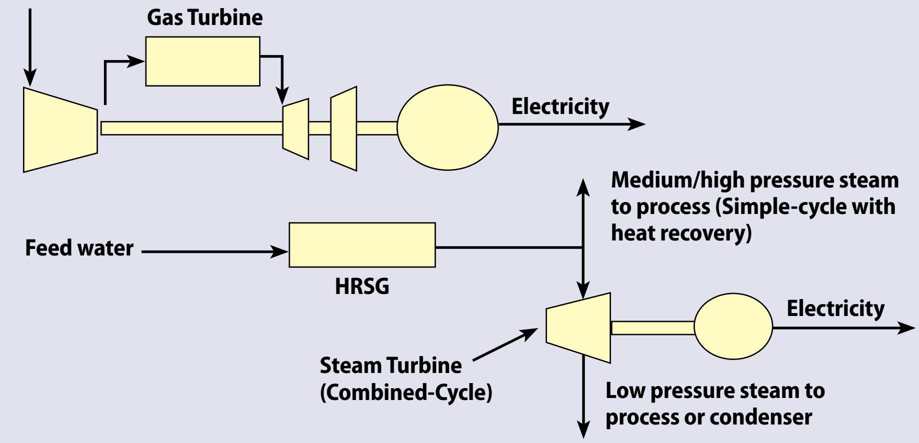
11 In some instances at existing CHP units, the revenue associated with the non-generation (heat supply) aspects of CHP operation can enable particular units to remain economically viable. Steam generator operation may be maintained even when there is no short-term market for the generated electricity. When these types of instances occur, the units tend to be operating very inefficiently.

12 ICF for DOE at supra footnote 3.

13 US EPA. Emission Factors and AP42. *Emission Factors: Stationary Internal Combustion Sources. Chapter 3: Stationary Gas Turbines.* Available at: http://www.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

Figure 2-3

Heat Recovery From a Gas Combustion Turbine Using a Heat Recovery Steam Generator[14]



objective will be highly dependent on site-specific factors — for example, plant equipment, geographic constraints, market conditions, steam requirements, pollution control equipment — which may make this category of GHG reduction potential fairly limited, particularly when considering only the electricity sector.

One practical and substantial constraint for CHP is the limited ability to move steam to where it can still be useful. Because steam can only be transported effectively over short distances, a power plant must be situated within close proximity to a district steam network or large industrial user.[15] Alternatively, the guarantee of long-term, low-priced steam energy can attract industrial, institutional, or commercial partners to build facilities or district steam networks adjacent to central station power plants, although the unique financial and partnership circumstances underlying such an investment decision are difficult to generalize.[16]

CHP also faces the challenge of finding concurrent load. In other words, to maximize energy savings, CHP is most advantageous for end-users with high and steady demand for thermal heat. Yet many of the power plants at which the installation of CHP might be technically feasible are gas turbines used as peaking units. Dispatched to meet peak demand for only a few hours or few hundred hours a year, these units would not generate a continuous enough supply of heat to satisfy industrial or district heat users.

Given the complexity of retrofitting existing EGUs, opportunities for developing new, utility-scale CHP using an industrial or energy park model may be more promising. Successful partnerships have created many opportunities in which cogeneration power plants and industrial facilities co-locate to take advantage of low-cost steam. A majority of CHP capacity in the United States today is made up of partnerships between large CHP generators (>100 MW) and industrial facilities. Looking forward, some of the new capacity additions required to offset anticipated coal-fired EGU retirements could be met through this sort of new and efficient utility-scale CHP.

2. Regulatory Backdrop

In response to the energy crisis of 1973, the United States enacted the Public Utilities Regulatory Policies Act (PURPA) in 1978, which required utilities to purchase electricity from cogeneration facilities as a means of

14 Supra footnote 7. In a combined-cycle gas turbine, high temperature exhaust is used to produce steam for a second cycle of power generation based on a steam turbine. If steam from the heat recovery steam generator is directed instead to meet space or process heating needs, it is considered a simple-cycle CHP unit.

15 In northern Europe, where CHP penetration is highest and much of it serves district heating demands, large transmission pipelines typically have a grid length of between 12 and 50 miles (20 to 80 kilometers). One of the European Union's largest networks, located in Aarhus, Denmark, has 81 miles (130 kilometers) of interconnected bulk heat pipeline fed by more than one source of thermal energy, rivaling the Con Ed Steam System in Manhattan, New York, which on a customer basis is considered the largest district steam system in the world. Cost effectiveness of piping thermal energy depends on demand density and total load, with losses decreasing with scale and pipe diameter. See: European Commission Joint Research Centre. (2012). *Background Report on EU-27 District Heating and Cooling Potentials, Barriers, Best Practices and Measures of Promotion.* Available at: https://setis.ec.europa.eu/system/files/JRCDistrictheatingandcooling.pdf; and International District Energy Association. (2005, August 5). *IDEA Report: The District Energy Industry.* Available at: http://lincoln.ne.gov/city/mayor/arena/assets/idea_district_energy.pdf

16 Great River Energy's facility in Underwood, North Dakota provides an example, described below.

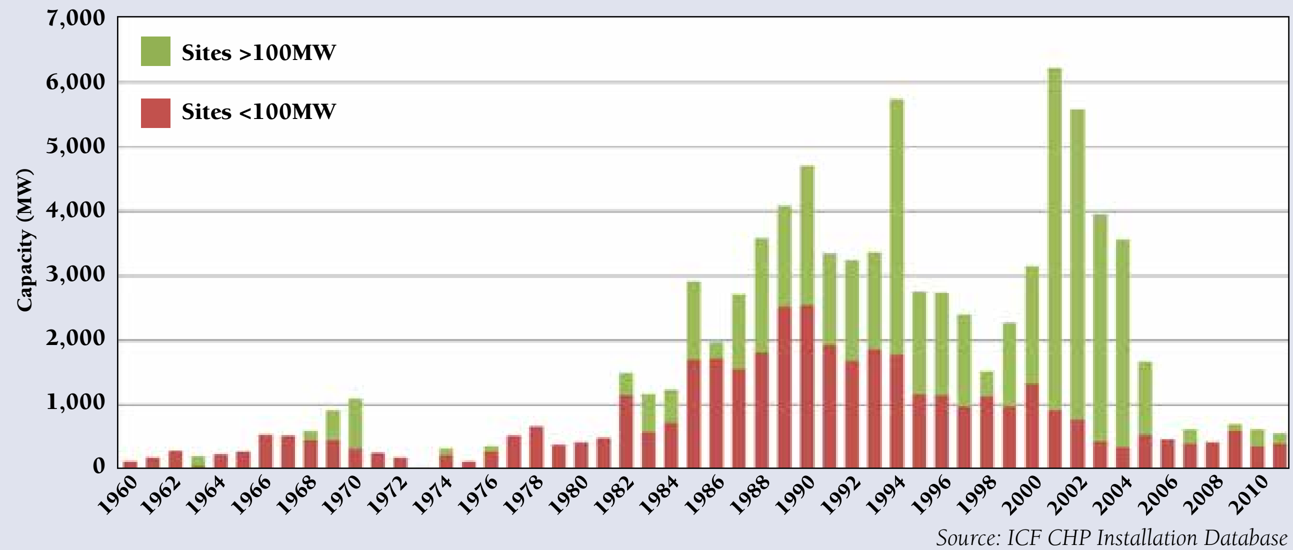
improving efficiency in the power sector. Under PURPA, utilities were obligated to interconnect all "qualifying facilities," to provide them with reasonable standby rates and backup charges, and to pay prices equivalent to the utilities' avoided cost of generation. These rules, along with subsequent tax incentives, spurred strong market growth from 1980 to 2005. Many of these facilities were owned by independent power producers, third-party CHP developers taking advantage of large-capacity combustion turbine technology that was newly available and capable of achieving high rates of electric output. Today, generating units over 100 MW account for 65 percent of a total US CHP capacity of 83 gigawatts (GW), almost all of which were built in the period following 1980 (Figure 2-4).[17]

The introduction of competitive wholesale markets beginning around the year 2000 affected the mandatory purchase requirement under PURPA. The 2005 Energy Policy Act eliminated the must-buy provision in instances in which larger customer-generators (>20 MW) had nondiscriminatory access to wholesale markets. These changes, coupled with general uncertainty in the face of market deregulation and volatile gas prices, led to a precipitous drop in investment in CHP, as shown in Figure 2-4. From 2005 to 2012, new investment remained largely stagnant and CHP capacity nationwide leveled off at around 80 GW.

Investment in CHP has increased in recent years. After a small upturn in market activity in 2012, 3.3 GW of new capacity are slated for construction between 2014 and 2016. Roughly half of that capacity is in installations greater than 100 MW.[19] There are a number of important drivers that are shaping this growth, including natural gas prices, air pollution regulations, state and federal capacity targets, and concerns about the reliability and resiliency of energy infrastructure. Regulatory drivers relevant to electric-sector CHP applications are described below.

Figure 2-4

Annual CHP Capacity Additions[18]



Source: ICF CHP Installation Database

17 ICF International for Oak Ridge National Laboratory. (2012). *CHP Installation Database*. Available at http://www.eea-inc.com/chpdata/index.html; and ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States*. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx

18 ICF International for American Gas Association, at supra footnote 17. Trends in capacity additions closely follow a changing regulatory backdrop, with the majority of CHP coming online between 1980 and 2005 and much of that in large-capacity units. Today, 65 percent of total installed capacity in the United States exists in units larger than 100 MW. Note that this figure does not reflect a recent uptick in additions, with nearly 1 GW added in 2012 and an anticipated 3.3 GW under construction and scheduled to come online between 2014 and 2016. Hampson, A. (2014). *CHP Market Status and Opportunities for Growth*. Presentation at the Electric Power Conference and Exhibition. ICF International.

19 Hampson A., at supra footnote 18. ICF International for US DOE, at supra footnote 3. ICF International for American Gas Association, at supra footnote 17.

Air Pollution Regulations

CHP units may be subject to permitting requirements and a variety of existing federal air pollution standards for criteria and hazardous air pollutant emissions, depending on the fuels combusted, the heat input or electrical output of the system, how much electricity is delivered to the grid versus used onsite, and the date of construction, reconstruction, or modification. Criteria pollutant emissions from CHP systems may be subject to New Source Performance Standards (NSPS) under one of the 40 C.F.R. Part 60 regulations, as follows:

- Subpart Da, for electric utility steam generating units;
- Subpart Db, for large industrial, commercial, and institutional steam generating units;
- Subpart Dc, for small industrial, commercial, and institutional steam generating units;
- Subpart IIII, for stationary compression ignition internal combustion engines;
- Subpart JJJJ, for stationary spark ignition internal combustion engines; or
- Subpart KKKK, for stationary combustion turbines.

Hazardous air pollutant emissions from CHP systems may be subject to National Emission Standards for Hazardous Air Pollutants (NESHAP) under one of the 40 C.F.R. Part 63 regulations, as follows:

- Subpart YYYY, for stationary combustion turbines;
- Subpart ZZZZ, for stationary reciprocating internal combustion engines;
- Subpart DDDDD, for large industrial, commercial, and institutional boilers and process heaters;
- Subpart UUUUU, for coal- and oil-fired electric utility steam generating units (often referred to as the Mercury and Air Toxics Standard or MATS rule); or
- Subpart JJJJJJ, for small industrial, commercial, and institutional boilers and process heaters.

As mentioned earlier, the proposed federal regulations for new and existing electric utility GHG emissions under sections 111(b) and 111(d) of the Clean Air Act would also apply to some CHP systems. Under the proposed existing source performance standard (the 111(d) rule), an affected EGU is defined as any steam generating unit, integrated gasification combined-cycle, or stationary combustion turbine that commences construction on or before January 8, 2014 and meets either of the following conditions:

- A steam generating unit or integrated gasification combined-cycle that has a base load rating greater than 73 MW (250 MMBTU[20]/h) heat input of fossil fuel (either alone or in combination with any other fuel) and was constructed for the purpose of supplying one-third or more of its potential electric output and more than 219,000 megawatt-hours (MWh) net-electric output to a utility distribution system on an annual basis; or
- A stationary combustion turbine that has a base load rating greater than 73 MW (250 MMBTU/h), was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a three-year rolling average basis, combusts fossil fuel for more than 10 percent of the heat input during a three-year rolling average basis, and combusts over 90 percent natural gas on a heat input basis on a three-year rolling average basis.[21]

The EPA proposed a nearly identical definition for new sources in the 111(b) rule. What is noteworthy for the purposes of this chapter is that the definition of affected source in both of the proposed electric sector GHG rules is crafted in a way that would exclude most CHP systems outside of the electric sector (the subject of Chapter 3) from regulation, because those systems are usually designed to deliver more than two-thirds of their electrical output for onsite use. CHP systems within the electric power sector are often larger and designed to deliver electricity to the grid, and thus are more likely to be affected by these proposed GHG regulations.[22] In support documents

20 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

21 US EPA. (2014). *40 C.F.R. Part 60. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

22 In a similar fashion, the regulatory definition of electric utility steam generating unit in existing NSPS and NESHAP rules is limited to units constructed for the purpose of supplying more than one-third of potential electric output capacity for sale rather than onsite use. This is significant because the existing NSPS and NESHAP rules for electric utility steam generating units are more stringent than for the other combustion technologies noted herein. This is also one of the reasons this document draws a distinction between CHP systems serving the electric power sector (the subject of this chapter) and CHP systems serving other sectors (the subject of Chapter 3).

published with the proposed 111(d) rule, the EPA reviewed data on nearly 3000 US CHP units and identified fewer than 500 that would meet the proposed definition of affected source.[23]

Some of the federal air regulations are designed in a way that acknowledges the emissions benefits of *combined* heat and power systems relative to *separate* heat and power systems. Most notably, the existing NSPS regulations for criteria pollutant emissions from electric utility steam generating units and the proposed NSPS regulations for electric utility GHG emissions allow CHP facilities to convert the useful thermal output of the system into an equivalent amount of electric output when demonstrating compliance with output-based emissions limits expressed in pounds per MWh (lb/MWh). This treatment of useful thermal output is explained in more detail in Section 4. Some air pollution regulations also acknowledge the dual nature of CHP systems in the definitions of affected sources. For example, the NSPS for criteria pollutant emissions from stationary combustion turbines applies to sources with a heat input at peak load equal to or greater than 10 MMBTU per hour, based on the higher heating value of the fuel, but heat input delivered to associated heat recovery steam generators or duct burners are not included when determining peak heat input.

Although most CHP systems in the electric sector are (or will be) subject to various regulations for criteria pollutant, hazardous air pollutant, and GHG emissions, and although compliance with regulations does increase costs, in some ways environmental regulations may be more of a driver for new CHP installations than an impediment. This is because output-based regulations and some of the special regulatory provisions included for CHP make the inherent efficiency of CHP an attractive alternative relative to other options. For example, the MATS rule and the NESHAP for large industrial, institutional, and commercial boilers and process heaters are expected to limit the emissions of roughly 1750 large industrial boilers, fired primarily by coal, oil, and biomass, putting pressure on owners to consider boiler replacement.[24] The latter rule includes special provisions to reward energy efficiency, whereby a firm can opt to use output-based standards to earn compliance credit for energy efficiency improvements at the facility level. This would add to the economic and operational appeal of adopting CHP as a means of complying with regulations.[25] As of August 2014, most compliance decisions had been made in preparation for the January 2016 deadline. The rule and the accompanying technical assistance program undertaken by the DOE[26] offer a model for how environmental regulations and government support can be designed to drive the market for CHP.[27]

The EPA's proposed 111(d) rule could significantly affect dispatch order for existing EGUs, including CHP units in the electric sector.[28] The EPA determined that the Best System of Emission Reduction includes an element of re-dispatch, specifically increasing the utilization rate of existing combined-cycle gas turbines. However, re-dispatch could potentially result in increased capacity factors for simple-cycle gas units as well, which in addition to the thermal credit afforded to CHP plants (discussed later), could make the economics more favorable for CHP. Whether CHP retrofit at an existing EGU is an appropriate option for GHG abatement, perhaps as a result of changes in dispatch, for example, would need to be ascertained on a site-by-site basis. As state planners, utilities, and grid operators face the combined effects of these and other changes in the electric system, and as plant managers consider making modifications to facilities to optimize boiler performance and improve heat rate (Chapter 1), an assessment of CHP feasibility should be included in that review process.

23 Based on data published by the EPA at: http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-egrid-methodology_0.xlsx

24 US DOE. (2013, February). *Summary of EPA Final Rules for Air Toxic Standards for Industrial, Commercial and Institutional Boilers and Process Heaters.* Available at: http://energy.gov/sites/prod/files/2013/11/f4/boiler_mact_article.pdf

25 Federal Register Section 63.7533 outlines the methodology for determining compliance using emissions credits and the EPA provides a hypothetical example online here: http://www.epa.gov/ttn/atw/boiler/imptools/energycreditsmarch2013.pdf

26 US DOE. (2014, May). *Boiler MACT Technical Assistance.* Available at: http://energy.gov/sites/prod/files/2014/05/f15/boiler_MACT_tech_factsheet_1.pdf

27 Chapter 3 discusses the boiler MACT in greater depth.

28 Building Block #2 titled *CO_2 Reduction Potential from Re-Dispatch of Existing Units.* See: US EPA. (2014, June 10). *Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants: GHG Abatement Measures.* Docket ID No. EPA-HQ-OAR-2013-0602 . Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

State and Federal Capacity Targets

State and federal capacity targets have been powerful tools in support of CHP. An Executive Order to Accelerate Investment in Industrial Energy Efficiency issued by the Obama Administration in 2012 set a national target of 40 GW of new, cost-effective CHP to be added by 2020.[29] Many states have also enacted capacity targets or included energy-efficient CHP as a qualifying resource in their energy efficiency or renewable portfolio standards (discussed in Chapters 11 and 16, respectively). As of 2013, 23 states had included CHP in either their energy efficiency or renewable portfolio standards,[30] which typically both puts a procurement obligation on utilities and offers financial incentives. California, New York, North Carolina, New Jersey, and Massachusetts are states that have adopted specific initiatives to support the development of CHP. Because most of the outreach related to these capacity targets has focused on CHP in sectors other than the electric power sector, this topic is covered in more detail in Chapter 3.

Reliability and Resiliency of Energy Infrastructure

CHP systems can serve as low-cost generation additions to the power system that reduce congestion and strain on transmission and distribution networks. Integrated with micro-grid and islanding capabilities, particularly to support hospitals, public security, and other critical infrastructure, CHP can enhance reliability and resiliency during grid disruptions. Recent natural disasters causing widespread and extensive grid failure have demonstrated the resiliency benefits of CHP and called attention to CHP as an important component of building robust energy infrastructure.[31] Following Hurricanes Sandy and Irene, Connecticut, New York, and New Jersey adopted CHP incentives.[32] And earlier, in response to devastating storms in the Gulf region, Texas and Louisiana adopted laws requiring critical government buildings to undertake feasibility studies for implementing CHP.[33]

3. State and Local Implementation Experiences

A review of US Energy Information Administration data for steam turbines at electric utility and independent power producer facilities indicates that in 2012 there were 121 EGUs at 81 facilities that were classified as topping-cycle steam CHPs. The nameplate capacity ratings for these EGUs ranged from 5 to 750 MW.

CHP installations across all sectors are regionally concentrated, as depicted in Figure 2-5, underscoring differences in electricity prices, policy environments, and industrial and manufacturing activities that are chief factors in CHP development. Large-scale petrochemical plants and refineries dominate in the Gulf Coast, where some of the country's largest cogeneration facilities are located. Biomass-fired cogeneration in the pulp and paper industry dominate in the Southeast and in Maine. In contrast, in states like California, New York, Massachusetts, Connecticut, and Rhode Island, CHP has been driven by a combination of high electricity prices and government initiatives. Proximity to buildings that have a high demand for thermal energy can also be a driver for CHP, especially in large northern cities where district heating and cooling is viable. State and local experiences with large-scale CHP facilities similarly demonstrate the local circumstances that create economic and partnership opportunities and lead to successful project development.

29 Executive Order 13624. (2012, August 30). *Accelerating Investment in Industrial Energy Efficiency.* 77 FR 54779. Available at: http://www.gpo.gov/fdsys/pkg/FR-2012-09-05/pdf/2012-22030.pdf

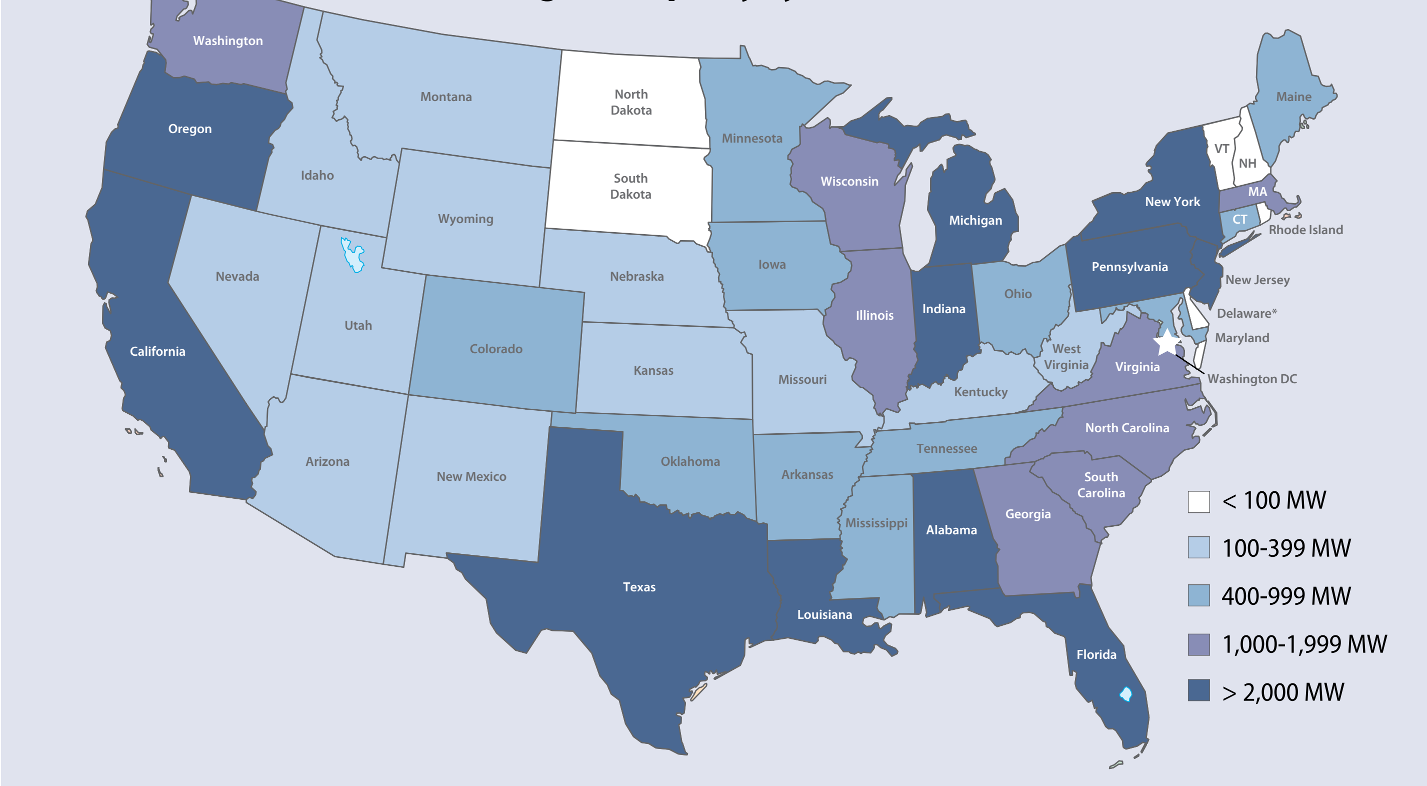
30 US DOE, EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies

31 A. Chittum. (2012, December 6). How CHP Stepped Up When the Power Went Out During Hurricane Sandy. [Web log post]. Available at: http://www.aceee.org/blog/2012/12/how-chp-stepped-when-power-went-out-d

32 CT P.A. 12 148 Section 7. (2012, July). *Microgrid Grant and Loan Pilot Program.* Available at: http://www.cga.ct.gov/2012/act/pa/pdf/2012PA-00148-R00SB-00023-PA.pdf

33 Texas HB 1831. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB01831F.pdf. Texas HB 4409. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB04409F.pdf. Louisiana Senate resolution No. 171. Available at: http://www.legis.la.gov/legis/BillInfo.aspx?s=12RS&b=SR171&sbi=y. For more extensive information on case studies see: ICF International for Oak Ridge National Lab. (2013, March). *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* Available at: http://www.energy.gov/eere/amo/downloads/chp-enabling-resilient-energy-infrastructure-critical-facilities-report-march

Figure 2-5



Existing CHP Capacity by State (2012)[34]

Although most large CHP plants are owned by third-party independent power producers or industrial facilities themselves, a common lesson from state and local experience is that utility involvement can be critical to project development. Customer-side generation signifies a decline in retail energy sales and has therefore traditionally presented a challenge to the utility business model. Utilities are in a unique position, however, to address many of the barriers facing CHP and take a leadership role in developing partnerships and designing projects to maximize benefits to both the customer and the electric system.

With a strong understanding of the electric delivery system, utilities can help identify where CHP projects would most effectively relieve grid congestion and reliability deficits. Owning and operating an EGU onsite may not be a feasible step for facilities that might benefit from the electrical and thermal output of CHP. However, utilities with the requisite technical expertise could help address those knowledge gaps. If the regulatory environment allows, a utility may own and operate the assets directly, or negotiate a package of services to provide support to the CHP owner. Another role for utilities is in project finance, where utilities typically have a lower cost of capital and are able to tolerate longer investment periods.

That utility ownership accounts for only three percent of CHP capacity may indicate a large untapped opportunity for utilities to capitalize on their unique position in this market.[35] A growing number of policymakers are exploring ways to enable utility participation in the CHP market as a means of addressing persistent administrative and financial barriers, and this may be a focus of regulatory efforts moving forward. Both a 2013 State and Local Energy Efficiency Action Network (SEE Action) study and a 2013 report from the American Council for an Energy-Efficient Economy (ACEEE) highlight possible considerations for utility participation in CHP markets; see these reports for more detail.[36]

34 ICF International for American Gas Association, at supra footnote 17.

35 Ibid.

36 Chittum, A. (2013, July). *How Electric Utilities Can Find Value in CHP.* ACEEE. Available at: http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf

Some specific trends and examples, highlighting utility-owned CHP, are discussed below. Additional case studies can be found online at the Database of State Incentives for Renewables and Efficiency and at the EPA's database of policies and incentives in support of CHP.[37]

The Alabama Power Company

Alabama Power, a subsidiary of Southern Company, exemplifies a model in which a vertically integrated utility both owns CHP units directly and coordinates customer ownership. Costs of utility-owned CHP and of power purchase agreements for customer-generated electricity are part of the company's rate base.

Alabama Power has approximately 2000 MW of CHP on its system, of which roughly 1500 MW is owned by customers. The remaining utility-owned CHP is composed of four large units located at industrial sites, including:

- 97 MW combined-cycle cogeneration plant located at Sabic Plastics in Burkville;
- 102 MW combined-cycle Washington County Cogeneration plant located at Olin Chemicals in McIntosh;
- 130 MW coal-biomass Gadsden Cogeneration plant located at Goodyear Tires and Rubber company; and
- 250 MW combined-cycle cogeneration plant located at the Phenolchemie facility in Theodore.[38]

Many of Alabama Power's CHP units were developed in response to the need to expand generating capacity to meet load obligations during the 1990s. Both utility-owned and customer-owned generation facilities were certified by the Alabama Public Service Commission through a flexible regulatory process, which allows non-steam aspects of the CHP facilities to be included in the utility's rate base. Alabama Power estimates that customer-owned generation has allowed it to avoid building 1.7 GW of central station capacity.[39]

Great River Energy

In the Midwest, Great River Energy (GRE) has taken a joint venture/subsidiary approach to address the financing and partnership challenges associated with integrated thermal-power applications in the biochemical sector. GRE is a member-owned transmission and generation non-profit serving distribution cooperatives in Minnesota and Wisconsin. It has two CHP facilities among its generation assets. The first, at Coal Creek Station in Underwood, North Dakota, was a retrofit to an 1100-MW mine mouth lignite-fired plant originally built in 1979-1980.[40] Although the retrofit itself required minimal modifications, GRE partnered with Headwaters Inc. to build a new ethanol plant at the site. Blue Flint Ethanol came online in 2007 with an annual capacity of 50 million gallons. Access to low-priced steam energy through a long-term contract, in addition to the roughly $5 million in avoided capital expenditure for the boiler and associated compliance requirements, gave the ethanol plant a competitive advantage over other, typically gas-fired, bio-refineries.[41]

GRE's second CHP facility is a new build. Spiritwood Station near Jamestown, North Dakota is the product of a partnership with Cargill Malt. In 2005, GRE was managing growth in electric demand of five percent per year and looking for sites to add new generation. Simultaneously, Cargill Malt was considering options to expand processing capacity and reduce energy costs at its plant in Spiritwood, a facility that dates back to the 1970s. Discussions led to siting a 99-MW lignite-fired power plant adjacent to the Cargill Malt plant. Originally designed to meet the needs of two users of thermal energy, plans stalled in 2008

37 Database of State Incentives for Renewables & Efficiency. Available at: http://www.dsireusa.org/. US EPA. (2014, August). *CHP Policies and Incentives Database*. Available at: http://epa.gov/chp/policies/database.html. Along with other examples discussed peripherally, the policy and implementation experiences of the state of Massachusetts are provided in detail in Chapter 3.

38 ICF International for US DOE and Oak Ridge National Laboratory. (2014). *CHP Installation Database: Alabama.* Available at: http://www.eea-inc.com/chpdata/States/AL.html

39 US DOE, EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies

40 GRE. (2014, August). *About Coal Creek Station.* Available at: http://www.greatriverenergy.com/makingelectricity/coal/coalcreekstation.html

41 This was true despite additional costs associated with transporting corn feedstock to the refinery, which were expected at the time of construction from 2005 to 2007 when Coal Creek was located on the margins of corn growing regions (corn agriculture has expanded in years since). GRE. (2014, August 15). Telephone conversation with Sandra Broekema, Business Development Manager.

when financing for the second user withdrew during the economic recession. GRE invested itself in the second user, Dakota Spirit AgEnergy, a conventional dry mill ethanol refinery, through its majority-owned Midwest AgEnergy Group.[42] The new facility, a 65-million gallon plant, is scheduled to come online in April 2015. The use of CHP steam has allowed the ethanol plant to meet the EPA's Renewable Fuel Standard 2, one of the first ethanol plants in the country to be approved under the lifecycle GHG performance standards added in 2007, which require a 20-percent reduction in emissions below a gasoline baseline.[43] Even with the ethanol plant, Spiritwood Station will have excess steam energy. Fully subscribed, the system is designed to achieve more than 65-percent efficiency.[44]

Other Utility-Ethanol Partnerships

The ethanol industry has many other instances of joint utility-customer CHP ownership. Two examples of municipal utility partnerships come from Missouri and are considered here. The City of Macon shares joint ownership of a gas-turbine CHP system with Northeast Missouri Grain, LLC, which runs an ethanol plant powered by steam from the CHP unit. This experience served as a model for another joint venture in Laddonia, Missouri. There, a partnership between the Missouri Joint Municipal Electric Utility Commission and Missouri Ethanol resulted in a 14.4-MW gas turbine system launched in 2006, which delivers 5 MW of power and 100,000 lb/h of steam to the adjacent 45-million gallon/year ethanol plant. In both examples, the utilities own and manage the gas turbine, while the ethanol companies have responsibility for the waste heat recovery unit and downstream steam system.[45]

4. GHG Emissions Reductions

Thermal recovery at an existing power plant reduces electrical output, but it improves energy utilization system-wide, thereby reducing fuel use and associated GHG emissions. Total GHG emissions from a CHP system can be roughly half the emissions that would occur from separate heat and power operations, as shown in Figure 2-1.

Output-based emissions factors are calculated using the measured emissions (in pounds of CO_2) and the productive output (whether MWh of electricity or MMBTU of steam) of the equipment under consideration. The two outputs of a CHP plant, electricity and thermal energy, are typically measured in different units (MWh and MMBTU). To express a plant's overall emissions factor and properly recognize the emissions benefits of CHP, the two outputs need to be converted into a single unit. A 2013 EPA guidance document on "Accounting for CHP in Output-Based Regulations" provides two approaches for incorporating a secondary output into emissions rate calculations.[46]

Equivalence Method

Under the equivalence approach, thermal output is converted to equivalent electrical units (e.g., 3.412 MMBTU/MWh) and added to the electric output to determine the total system output. The emissions of the CHP system are then divided by the total output to determine an emissions rate in terms of lb/MWh.

The equivalence method is used, for example, by the state of Texas in its Permit by Rule and Standard Permit regulations, and in California in its conventional emissions limits and emissions performance standards for CHP.[47]

42 Midwest Energy News. (2014, May 13). *Prospects Turning Around for Embattled Spiritwood Coal Plant.* Available at: http://www.midwestenergynews.com/2014/05/13/prospects-turning-around-for-embattled-spiritwood-coal-plant/

43 US EPA Office of Air and Radiation. (2013, February 6). *RFS2 Petition From and Letter of Approval to Dakota Spirit AgEnergy.*

44 GRE. (2014, August). *About Spiritwood Station.* Available at: http://www.greatriverenergy.com/makingelectricity/newprojects/spiritwoodstation.html

45 Bronson, T., Crossman, K., & Hedman, B. (2007, 2nd Quarter). *Utility-Ethanol Partnerships: Emerging Trend in District Energy/CHP.* International District Energy Association. Available at: http://www.epa.gov/chp/documents/district_energy_article.pdf

46 US EPA CHP Partnership. (2013, February). *Accounting for CHP in Output-Based Regulations.* Available at: http://www.epa.gov/chp/documents/accounting.pdf

47 Ibid.

In some instances, regulations may specify a certain percentage of credit to be allotted. The NSPS for utility boilers originally issued in 1998 stipulated the equivalence method, but originally applied a 50-percent credit[48] — later amended to 75 percent in 2006 — such that only that portion of the thermal output would be factored into the total system output. Note the value of the conversion factor depends on the underlying regulatory objectives. States like California, Texas, and Massachusetts ascribe a 100-percent credit for thermal output as a way to encourage CHP.

The proposed 111(b) and 111(d) rules for electric power sector GHG emissions use the equivalence method to award CHP systems with a MWh credit equivalent to 75 percent of the useful thermal output. The EPA provides an example of this accounting approach in correspondence with the Office of Management and Budget,[49] based on the following hypothetical plant specifications:

- 100 MW electric output;
- 500 MMBTU/h of useful steam output; and
- 200,000 lb CO_2/h measured emissions rate.

The thermal output rate of 500 MMBTU/h would be converted to an equivalent MW of output (3.412 MMBTU/h = 1 MWh), whereby 500 MMBTU/h = 147 MW. The resultant value would be multiplied by 75 percent to get a value of 110 MW, which would be added to the electric output to calculate the facility's emissions rate. For comparison against the applicable emissions standard — whether the 1000 lb CO_2/MWh or 1100 lb CO_2/MWh standard — the facility emissions rate would be (200,000 lb CO_2/h) / (100 MW + 110 MW) or 950 lb CO_2/MWh.

The EPA's proposed 111(b) and 111(d) rules would further reward CHP by applying an additional five-percent line loss credit to the net electric output to capture the transmission and distribution losses that are avoided through onsite power generation. The line loss credit would apply to CHP facilities where useful thermal output and electric output (or direct mechanical output) both account for at least 20 percent of total gross output.

Data from GRE's Coal Creek Station, the retrofit CHP coal plant mentioned previously, illustrate how CHP can improve carbon intensity calculations at the EGU level. Table 2-2 examines CO_2 emissions rates for 2007, the first year of thermal sales to the co-located Blue Flint Ethanol plant. Factoring in the 75-percent credit for thermal output, the CO_2 emissions rate for total gross energy output (i.e., electric + 75 percent of thermal) was 2119 lb/MWh. An alternative, non-CHP scenario assumes that the steam extracted off the turbine was instead used to generate

Table 2-2

Comparison of CO_2 Emissions Rates With and Without Thermal Energy Exports at Coal Creek Station (2007)[50]

Electric-Only			CHP			Non-CHP Scenario			CO_2 Intensity, % Improvement with CHP
CO_2, tons/yr	Gross Load, MWh/yr	CO_2, lb/MWh	Gross Steam Transfers, MMBTU/yr	Gross Energy Output, MWh/yr	CO_2, lb/MWh Gross Output	Reduced Electrical Output, MWh/yr	Gross Energy Output, MWh/yr	CO_2, lb/MWh Gross Output	
10,141,763	9,262,539	2190	1,400,111	9,570,211	2119	94,973	9,357,512	2167	2.2%

48 Discussion of this point can be found in Section 5.2.5 of: US EPA. (1998, September). *New Source Performance Standards, Subpart Da and Db – Summary of Public Comments and Response.* Available at: http://www.epa.gov/ttn/oarpg/t1/reports/nox-fdoc.pdf

49 US EPA. (2013, August 2). Summary of Interagency Comments on US Environmental Protection Agency's Notice of Proposed Rulemaking "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" (RIN 2060-AQ91), EPA-HQ-OAR-2013-0495-0045. Available at: http://www.eenews.net/assets/2014/02/04/document_daily_02.pdf

50 "Gross Steam Transfers" incorporates the total mass of steam transferred to Blue Flint Ethanol in 2007 and a weighted average enthalpy of steam of 1306.10 BTU/lb. For the "Non-CHP Scenario," because of the specific CHP configuration at Coal Creek, only roughly 88 percent of the exported steam would have been used to generate additional power; to this portion, the plant's average performance ratio of 10,000 lb of steam per MWh of electrical output is applied to calculate the reduced electrical output. Steam transfers and reduced electrical output data were provided by GRE for the year 2007. Other emissions and operational data were derived from the EPA's online Air Markets Program Database and confirmed by GRE.

additional electricity at a rate of 1 MWh of electrical output per 10,000 lb of steam. Under this scenario, the plant would have had an emissions rate of 2167 lb/MWh. In this way, the export of thermal energy at Coal Creek Station resulted in a 2.2-percent improvement in the facility's CO_2 emissions rate in 2007. Because exported steam at Coal Creek amounted to less than 20 percent of gross energy output in 2007, the five-percent line loss credit would not apply.

The amount of energy output calculated by the equivalence method varies significantly depending on the *power-to-heat ratio* of a CHP unit. The power-to-heat ratio is an important factor with regard to CHP system efficiency. Owing to the low conversion efficiency of electric generation (e.g., an average 33 percent for coal-fired steam turbines), CHP units that produce proportionally more electricity relative to thermal energy (i.e., units with a high power-to-heat ratio) will have a lower total useful output, and therefore a higher emissions factor. As a result, the more thermal output from a system, the lower that system's CO_2 emissions factor would be.

On the one hand, the equivalence method recognizes thermal output, but the effect of this accounting method is largely a function of the relative amounts of thermal and electric energy produced by the CHP system. The method does not reflect the actual environmental benefit provided by CHP in displacing conventional emitting thermal units.

Avoided Emissions Approach

Alternatively, the avoided emissions approach compares the emissions of the CHP system with the emissions that would have been produced had the thermal energy been generated separately in a conventional boiler.[51] Under this approach, the output-based emissions rate for a CHP system is expressed in terms of its electrical output. This approach assumes the CHP system displaces emissions that would have otherwise occurred in the separate production of electricity and useful thermal output. The net emissions are then divided by the unit's electrical output to determine the emissions rate in terms of lb/MWh. The calculation incorporates only the system's electrical output. Regulations would specify default assumptions; avoided thermal emissions, for example, may be based on the performance of a new source, such as a natural gas-fired boiler with 80-percent efficiency and a standard emissions rate of 0.05 lb per MMBTU of heat input. The avoided emissions approach is particularly relevant to CHP systems at industrial, commercial, and institutional facilities and thus is explained in greater detail in Chapter 3.

Delaware and Rhode Island have used the avoided emissions method in conventional emissions limits for CHP; Connecticut and Massachusetts also use this approach in accounting for small distributed generation.[52] There is general consensus that the avoided emissions approach more closely approximates the environmental attributes of a CHP application, although the equivalence approach is often preferred for its simplicity.

5. Co-Benefits

CHP systems within the electric power sector can deliver a wide range of benefits to the utility system and to society. To begin with, although the earlier discussion focused on the GHG emissions reductions that can be achieved through CHP, similar reductions in criteria and hazardous air pollutant emissions are possible. The methods for quantifying those reductions are essentially the same as the methods used to calculate GHG reductions, with the avoided emissions approach offering a more accurate picture of the impacts.

In addition to reduced pollution, CHP provides broader societal benefits. For instance, installations can be configured with micro-grids to support critical infrastructure and enhance resiliency for emergency response and preparedness. By improving competitiveness, CHP can play a role in strengthening the US manufacturing sector. Furthermore, investment in the energy sector can also be expected to stimulate demand for skilled jobs.[53] A DOE study found that achieving the national goal of

51 The Regulatory Assistance Project. (2003). *Output Based Emissions Standards for Distributed Generation.* Available at: http://www.raponline.org/docs/RAP_IssuesLetter-OutputBasedEmissions_2003_07.pdf

52 Supra footnote 47. Other examples can be found in Appendix B of the EPA's 2003 handbook for air regulators on output-based regulations. US EPA. (2004). *Output-Based Regulations: A Handbook for Air Regulators.* CHP Partnership.

53 A 2008 Oak Ridge National Laboratory study found a CHP goal of 20 percent of generation capacity would stimulate $234 billion in capital investment and create nearly one million new jobs by 2030. Shipley, A., Hampson, A., Hedman, B., Garland, P., & Bautista, P. (2008, December 1). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* ORNL for US DOE. Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf

developing 40 GW of additional CHP would save one quadrillion BTUs of energy annually, prevent 150 million metric tons of CO_2 emissions annually, and save $10 billion per year in energy costs, while attracting $40 to $80 billion in new capital investment in manufacturing and other US facilities over the next decade.[54]

From the perspective of utilities, CHP avoids significant line losses, allows deferral of costly investments in new transmission and distribution infrastructure, and represents low-cost capacity additions, all of which can in turn translate into lower bills for rate-payers. The full range of potential co-benefits for society and the utility system are summarized in Table 2-3.

Table 2-3

Types of Co-Benefits Potentially Associated With Combined Heat and Power in the Electric Sector

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Yes
Other	

When a utility customer receives the thermal output from a utility-owned CHP system, the customer may enjoy additional benefits not shown in Table 2-3. From the perspective of these customers, CHP can improve competitiveness by reducing energy costs. Using thermal energy from an adjacent CHP facility can result in avoided capital expenditure and may help mitigate the customer's own environmental compliance costs. Another motivating factor for participants is greater supply reliability, because CHP can reduce risks posed by grid disruptions. Many of these co-benefits have been alluded to earlier and are further discussed in Chapter 3.

6. Costs and Cost-Effectiveness

CHP is generally regarded as one of the most cost-effective ways to reduce CO_2 emissions economy-wide, a finding confirmed by numerous studies in recent years. A 2009 report by McKinsey & Company, for example, found that 50 GW of CHP in industrial and large commercial/institutional applications would yield positive net-present values over the lifetime of the investment.[55] Economic potential of the same order of magnitude was found by a more recent ICF study, which concluded that 42 GW of CHP technical potential[56] (across all sectors, not just the electric power sector) had an investment payback period of less than ten years across the United States.[57]

New CHP installations can be particularly cost-effective, whereas retrofitting existing EGUs to a CHP configuration

54 US DOE & US EPA. (2012, August). *Combined Heat and Power: A Clean Energy Solution.* http://www.epa.gov/chp/documents/clean_energy_solution.pdf

55 Those projects would result in reductions of 100 million metric tons of CO_2 across the country annually through 2020. Updating that analysis to incorporate today's natural gas prices would likely improve those estimates substantially. McKinsey & Company, at supra footnote 4.

56 Technical potential as defined in the ICF analysis accounts for sites that have concurrent thermal and electric demands suitable to CHP, but does not consider economic factors relevant to project investment decisions, nor does it include existing EGUs.

57 Economic viability was screened by incorporating energy prices (excluding other economic incentives). ICF International for American Gas Association, at supra footnote 17.

can be cost-effective in the right circumstances. Capital costs for new boiler/steam and gas turbine CHP units vary significantly based on size, fuel type, fuel accessibility, geographic area, operational specifications, and market conditions, among other factors.[58] Using 2013 dollars, the EPA estimates that for simple installations, new gas turbine CHP costs typically range from $1200/kW to $3300/kW (4 to 50 MW), and new steam turbine CHP units may range anywhere from $670/kW to $1100/kW, with complete plant costs typically greater than $5000/kW. Retrofit costs for boiler/steam and gas turbine CHP units are even more highly dependent on site-specific configuration requirements. This makes it difficult to generalize about costs and cost-effectiveness.

One of the factors that strongly influences the cost-effectiveness of CHP systems is the price of fuel. Increased domestic natural gas production has radically altered the market outlook for gas, reducing prices and volatility.[59] Most forecasts anticipate an increase in electricity prices against continuously low natural gas prices, improving the economic viability of gas-powered demand-side generation. Clean burning gas, already the preferred fuel for CHP applications, will likely enable future growth and greater investment in CHP.

The underlying economics of retrofit opportunities will weigh the capital cost of modifications to the plant against the tradeoffs between reduced power capacity on the one hand and steam energy output on the other. Factors including fuel costs, operating hours, wholesale power prices, the terms of steam contracts, and investment and management arrangements at the facility, would all bear strongly on this financial analysis. Therefore, although retrofitting CHP as a means of improving emissions performance is theoretically an option for EGUs facing compliance with GHG regulations, in practice, whether these factors amount to a favorable investment opportunity would likely be determined by unique circumstances. The EPA has done some evaluation of costs of retrofitting turbines into existing boiler/steam systems, but in the course of research for this chapter no studies were found to have surveyed retrofits at EGUs specifically.

Given the complexity of EGU retrofits, opportunities for developing utility-scale CHP as a source of new generating capacity may have greater relevance. A 2012 report by the DOE and the EPA included an analysis of delivered electricity costs in New Jersey.[60] Figure 2-6 compares costs of power generated from small-, medium-, and large-sized CHP systems, with retail rates and the cost of delivered electricity from central power generators across a mix of resources. The light gray block at the top of the CHP bars denotes the thermal energy cost savings. Net costs of electricity from medium- and large-scale CHP are lower than retail rates in their respective customer classes, and are more competitive than the combined-cycle gas turbine, coal, wind, and photovoltaic when transmission and distribution costs are taken into account. Producing power for the grid, new CHP EGUs would retain associated transmission and distribution costs for offsite electric customers. Adding these costs back in, large CHP would still be roughly on par with the combined-cycle gas plant, and medium-sized CHP would continue to hold an advantage against wind and coal.

Whether through pay-back period, net-present value, levelized costs of energy, or return on investment metrics, there are numerous ways to evaluate cost-effectiveness. And there are various perspectives from which to evaluate it, whether from that of the participants, the gas utility, the electric utility, the ratepayer, or society generally. Additional analyses of the cost-effectiveness of CHP generally are summarized in Chapter 3.

58 See Table 3-4 of Chapter 3 for cost estimates across technology classes. Within the same fuel and configuration class, costs display a clear scale effect, with costs per kW of capacity generally decreasing as size increases. Also, the amount of steam extracted for thermal purposes, and thus not available for electricity generation, significantly affects the costs (in $/kW) of electricity output. US EPA. (2014, September). *Catalog of CHP Technologies*. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

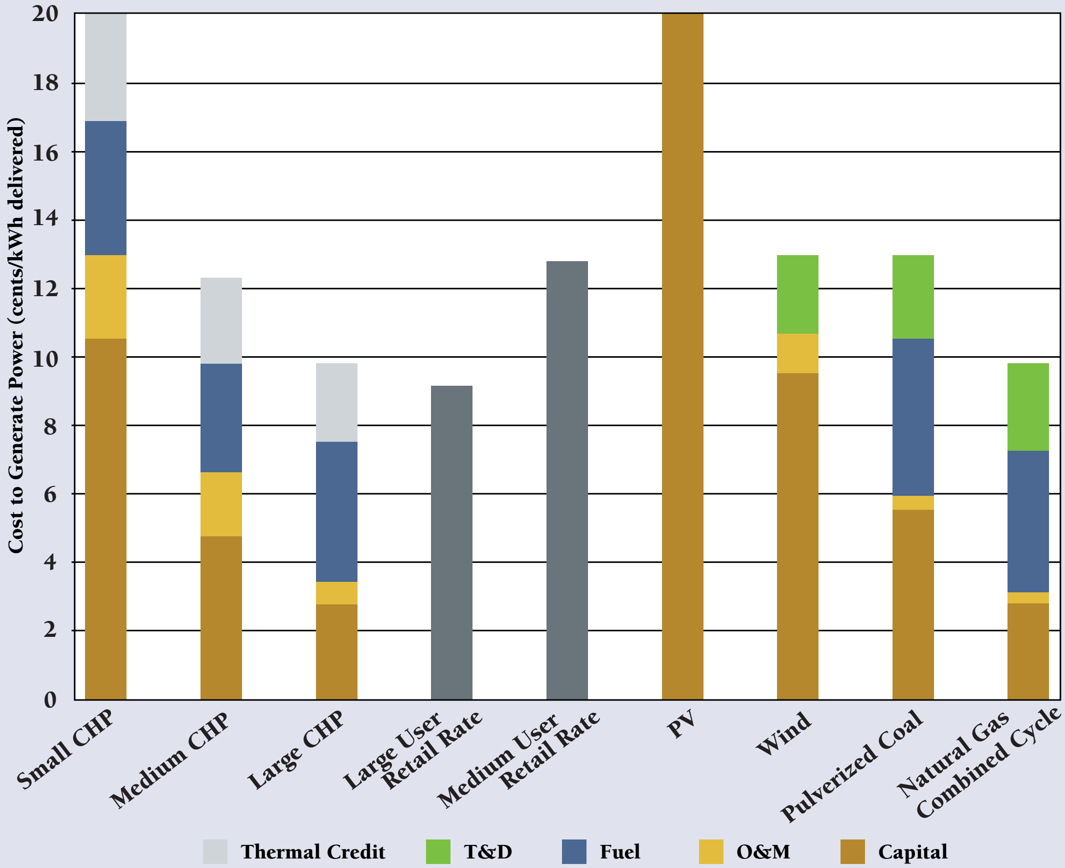
59 Known as a "spark spread," this favorable ratio of gas prices to electricity prices provides increased motivation to CHP producers.

60 Supra footnote 54.

Figure 2-6

CHP Can Be a Cost-Effective Source of New Generation Capacity[61]

Cost of Delivered Electricity — New Jersey



7. Other Considerations

Utility ownership of CHP assets can pose interesting challenges for utility regulators. One issue that often arises is the challenge of deciding how much of the system costs should be paid by electric utility customers in general (and recovered in utility rates) versus how much should be paid by the customer(s) using the CHP system's thermal output. There may also be questions about how to allocate system costs and any revenues from the sale of thermal output to different customer classes. Finally, the risk of stranded assets will also be a significant concern for utility regulators, who must concern themselves with the possibility that a customer who is expected to purchase the thermal output from a long-lived, expensive CHP system, will in the future no longer need the thermal output, or be able to pay for it. Without a customer for the thermal load, the CHP system might someday be uneconomical, but utility customers will still be expected to pay for it. This is what utility regulators call a "stranded asset."

61 Supra footnote 54. Costs of delivered electricity across resource classes and retail rates show that CHP can provide cost-effective generation capacity additions. Note that the light gray block at the top of the CHP bars denotes the thermal energy costs savings. Assumptions: capital and operations and maintenance costs for coal, natural gas combined-cycle, wind, and photovoltaics, and annual capacity factors for wind and photovoltaics based on EIA AEO 2011; annual capacity factors for coal and natural gas combined-cycle based on 2009 national averages (64 and 42 percent, respectively); utility coal and natural gas prices \$4.40/MMBTU and \$5.50/MMBTU, respectively, CHP based on 100-kW engine system and \$7.50/MMBTU natural gas (small CHP), 1-MW engine system and \$6.25 natural gas (medium CHP), 25-MW gas turbine and \$6.25 natural gas (large CHP); cost of capital 12 percent for CHP and 8 percent for central station systems.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CHP in the electric sector.

- ACEEE. *Technical Assistance Toolkit, Policies and Resources for CHP Deployment*. Available at: http://aceee.org/sector/state-policy/toolkit/chp
- ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States*. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx
- NASEO. (2013). *Combined Heat and Power: A Resource Guide for State Energy Officials*. Available at: http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf
- SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies*. US DOE and US EPA. Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
- US DOE. CHP Technical Assistance Partnerships website: http://www1.eere.energy.gov/manufacturing/distributedenergy/chptaps.html
- US DOE and Oak Ridge National Laboratory. (2012). *Guidance for Calculating Emission Credits Resulting From Implementation of Energy Conservation Measures*. Available at: http://info.ornl.gov/sites/publications/Files/Pub37258.pdf
- US DOE and Oak Ridge National Laboratory. (2008, December). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*. Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf
- US EPA. (2014, July 30). *CHP Emissions Calculator*. Available at: http://www.epa.gov/chp/basic/calculator.html
- US EPA. (2014, July 30). *AVERT*. Available at: http://epa.gov/avert/
- US EPA. (2013, February). *Accounting for CHP in Output-Based Regulations*. Available at: http://www.epa.gov/chp/documents/accounting.pdf
- US EPA. (2012, August). *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems*. Available at: http://www.epa.gov/chp/documents/fuel_and_co2_savings.pdf
- US EPA. (2014). *Output-Based Regulations: A Handbook for Air Regulators*. Available at: http://www.epa.gov/chp/documents/obr_handbook.pdf
- US EPA CHP Partnership website: http://www.epa.gov/chp/
- US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies*. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

9. Summary

CHP provides a cost-effective, commercially available solution for near-term reductions in GHG emissions, with large technical potential distributed across the country. CHP results in direct energy savings to the user, and offers a host of wider societal benefits, including reductions in air pollution, enhanced grid reliability, low-cost capacity additions, and improved resiliency of critical infrastructure. Retrofit opportunities at existing EGUs will be limited, however, by site-specific factors. Such factors include the geographic proximity to suitable users of thermal energy, and the need to incorporate enough thermal recovery to bring the unit into compliance, while balancing the tradeoff between reduced power production on steam turbines and thermal energy sales. Assessments of CHP feasibility could be undertaken by plant management as they review options for improving heat rate performance, such as those outlined in Chapter 1. As for new construction, larger-scale CHP facilities that integrate the operations of generators with industrial partners offer a cost-competitive alternative to central power production and cost-effective replacement capacity for aging plants poised for retirement. CHP projects are often complex, custom installations with equally complex legal and financial arrangements between partnering entities. Therefore, despite the technology being mature, substantial administrative burdens persist and keep rates of adoption low even in jurisdictions with favorable regulatory environments. Supportive policies and regulations will be required to take full advantage of CHP opportunities, whether as stipulated in the EPA's final 111(b) and 111(d) rules or otherwise in plans and accounting requirements developed by states.

3. Implement Combined Heat and Power in Other Sectors

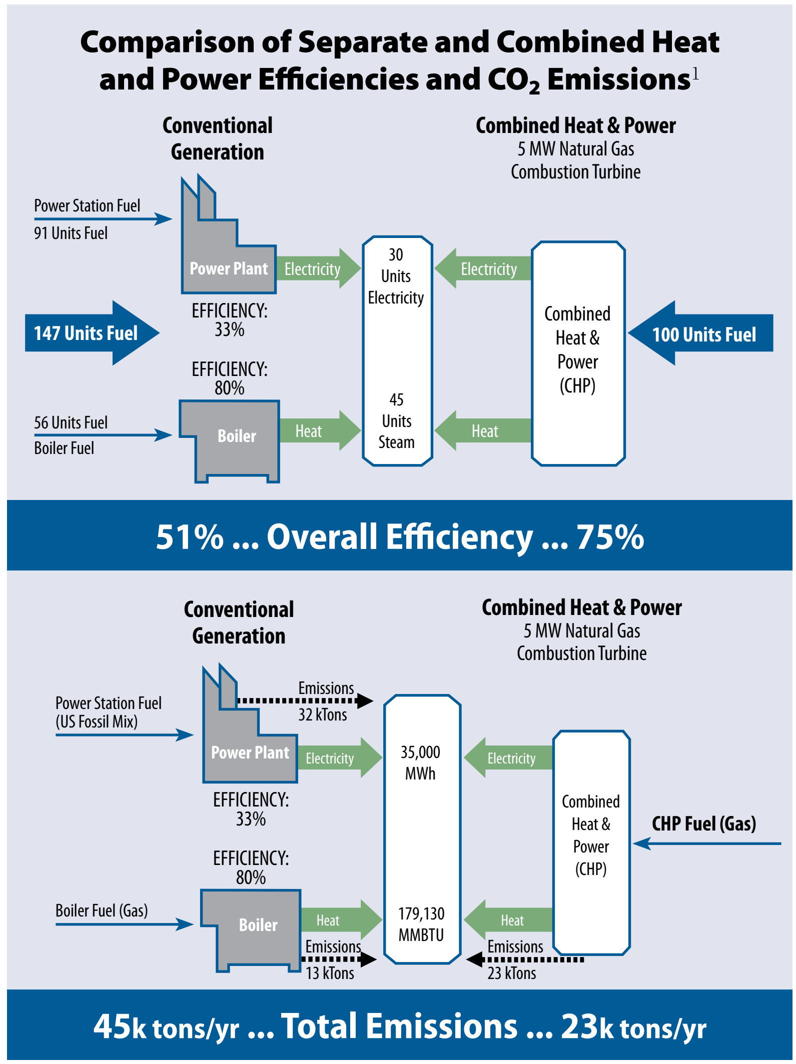
1. Profile

Combined heat and power (CHP) technologies in the commercial, institutional, and manufacturing sectors can reduce carbon dioxide (CO_2) emissions across the economy through system-wide gains in energy efficiency that improve economic competitiveness. Because CHP systems in these sectors indirectly reduce the need for generation within the power sector, they may even play a role in state plans for complying with federal regulations covering power sector greenhouse gas (GHG) emissions, such as the rules proposed by the US Environmental Protection Agency (EPA) in 2014 under sections 111(b) and 111(d) of the Clean Air Act.

CHP, also known as cogeneration, refers to a variety of technology configurations that sequentially generate both electric and useful thermal output from a single fuel source. As discussed in Chapter 2, CHP can take the form of large-capacity power producers that sell bulk electricity to the grid while supplying neighboring industrial facilities or district energy systems with thermal energy for process or space heating purposes. But CHP can also be installed at facilities with onsite or nearby demand for both heating or cooling and electricity, such as manufacturing facilities, universities, hospitals, government buildings, multifamily residential complexes, and so forth, as decentralized generation assets ranging in size and distributed across the electric grid. CHP as a form of distributed generation for these types of facilities is the subject of this chapter.

By displacing onsite boiler use and grid-supplied electricity, CHP systems can ensure supply reliability, save fuel, and reduce operating costs, typically achieving combined efficiencies of 60 to 80 percent as opposed to the 40 to 55 percent that might be expected from separate heat and power operations. These energy savings can amount to a

Figure 3-1



50-percent reduction in carbon emissions (Figure 3-1). Beyond the facility utilizing CHP, they can deliver a host of societal benefits, including improved environmental

1 US EPA. (2014, August). *CHP Partnership*. Available at: http://www.epa.gov/chp/. A power plant efficiency of 33 percent (higher heating value [HHV]) denotes an average delivered efficiency based on 2009 data from eGRID for all fossil fuel power plants of 35.6 percent, plus 7 percent transmission and distribution losses.

performance, high quality jobs, reduced congestion on the electric grid, reduced line losses, and embedded resiliency for emergency response and preparedness.

There are two basic types of CHP, what are referred to as bottoming and topping systems. A "topping-cycle" system is the most common configuration, in which fuel is used to power a steam turbine or combusted in a prime mover, such as a gas turbine or reciprocating engine, with the purpose of generating electricity. Rejected heat is then captured and used for process or space heating needs. In a "bottoming-cycle" system, also called "waste heat to power" (WHP), the fuel is first used to deliver a thermal input to an industrial process, and waste heat is recovered for power generation (see text box on page 3-3).

As a form of distributed generation, CHP can be based on a variety of generation technologies, summarized in Table 3-1, such as combustion turbines, steam turbines, reciprocating engines, microturbines, and fuel cells. These

Table 3-1

Summary of CHP Technologies[2]

CHP System Type	Advantages	Disadvantages	Available Sizes	Overall Efficiency (HHV)	Installed, 2014 (Capacity/ Sites)[3]
Gas Turbine	High reliability. Low emissions. High-grade heat available. Less cooling required.	Requires high-pressure gas or in-house gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.	500 kW to 300 MW	66% to 71%	64%/16%
Steam Turbine	High overall efficiency. Any type of fuel can be used. Ability to meet more than one site's heat grade requirement. Long working life and high reliability. Power to heat ratio can be varied within a range.	Slow start-up. Low power-to-heat ratio.	50 kW to 300+ MW	Near 80%	32%/17%
Reciprocating Engine	High power efficiency with part-load operational flexibility. Fast start-up. Has good load following capability. Can be overhauled onsite with normal operators. Operates on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions.[4] Must be cooled even if recovered heat is not used. High levels of low frequency noise.	1 kW to 10 MW in distributed generation applications	77% to 80%	3%/52%
Fuel Cell	Low emissions and low noise. High efficiency over load range. Modular design.	High costs. Low power density. Slow startup. Fuels requiring processing unless pure hydrogen is used.	5 kW to 2 MW	55% to 80%	0.1%/4%
Microturbine	Small number of moving parts. Compact size, light weight. Low emissions. No cooling required.	High costs. Relatively low electrical efficiency. Limited to lower temperature cogeneration applications.	30 kW to 250 kW	63% to 70%	0.1%/8%

kW: kilowatt
MW: megawatt

2 US EPA. (2015, March). *Catalog of CHP Technologies.* Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf. Note that these are illustrative values intended to represent typical CHP systems. CHP efficiency varies with size and power-to-heat ratio.

3 The data in the last column indicate each system type's percentage of total installed US CHP capacity (83.3 gigawatt) and total number of installations (4220 sites) as of 2014. Ibid.

4 Note that reciprocating engines can be configured to produce lower levels of emissions through engine design and add-on controls.

various technology configurations can consume a range of fuels, including oil, biomass, landfill gas, biogas, and hydrogen, but natural gas is the most common, accounting for 70 percent of existing CHP capacity.[5] The revolution in shale gas production has boosted domestic natural gas supplies, reducing both prices and volatility, which,

WHP describes any number of applications by which waste heat is captured from an industrial process through heat exchange to generate electricity. Since the 1970s, steam turbines have been used to generate power from high temperature exhaust. More recent advances allow heat recovery at lower temperatures and smaller scales – using the Organic Rankine Cycle, Kalina Cycle, and the Stirling Engine, for example – permitting power generation from a broader range of industrial applications. Technology is continuing to evolve, expanding the viability of WHP applications to low quality heat, where the majority of industrial heat losses occur.[6]

The Organic Rankine Cycle accomplishes heat transfer at low temperatures using an organic working fluid instead of water. Carbon-based refrigerants with high molecular weight can improve the heat transfer efficiency because they possess a lower boiling point than that of water.[7] The Kalina Cycle is a type of Rankine Cycle that achieves greater efficiencies by using a mixture of two fluids with different boiling points, typically ammonia and water, to extract energy across a wider range of temperature inputs. The Organic Rankine Cycle and Kalina Cycle are the same technologies used to generate power from renewable resources, such as geothermal and solar. In the industrial sector, primary metals, minerals manufacturing, chemical industry, petroleum refining, natural gas compressor stations, and landfill gas systems represent some of the industries that involve numerous processes with potential for WHP.[8,9]

As a technology category, WHP includes ***bottoming-cycle cogeneration*** as it is defined in this chapter, that is, instances in which waste heat is recovered from a thermal process, like a cement kiln or glass furnace, to generate electricity. However, WHP also includes applications in which waste heat is recovered from industrial processes that are not thermal, for example, from natural gas compressor stations. The term combined heat and power is often defined narrowly so as to exclude applications that are delivering useful services other than heating and cooling. Furthermore, Congress, federal agencies, and states have conflicting definitions, such that bottoming-cycle cogeneration and other WHP applications may be excluded from incentive programs – if not in spirit, then only by letter of the law. An example with large repercussions for the WHP market is Section 48 of the Tax Code, which provides a ten-percent investment tax credit for topping-cycle CHP only.[10] One approach taken by states seeking to support industrial efficiency through their portfolio standards has been to define CHP and WHR separately. Eighteen states specifically identify WHP as a qualifying resource in their Renewable, Clean Energy, or Energy Efficiency Portfolio Standards.[11]

5 The second most dominant fuel in CHP installations is coal, at 15 percent of US CHP capacity as of March 2014. ICF International for US Department of Energy and Oak Ridge National Laboratory. (2014, March). *CHP Installation Database*. Available at: http://www.eea-inc.com/chpdata/

6 The US Department of Energy estimates that 60 percent of industrial waste heat is below 450°F, whereas 90 percent is below 600°F. US Department of Energy. (2008). *Waste Heat Recovery: Technology and Opportunities in US Industry.* Available at: http://www1.eere.energy.gov/manufacturing/intensiveprocesses/pdfs/waste_heat_recovery.pdf

7 In the past, choice working fluids for Organic Rankine Cycle were ozone-depleting substances phased out under the Montreal Protocol and replaced by hydrofluorocarbons and perfluorocarbon compounds with high global warming potential, now also in the process of being phased out. Low global warming potential, zero ozone-depleting substance refrigerants like hydrocarbons and other compounds are now being brought into use as substitutes.

8 US EPA. (2012, May 30). *Waste Heat to Power Systems.* (Case studies.) Available at: http://www.epa.gov/chp/documents/waste_heat_power.pdf. Case studies.

9 For detailed project profiles, see: Heat Is Power. (2014). *Case Studies.* Available at: http://www.heatispower.org/waste-heat-to-power/case-studies/

10 26 US Code § 48 - Energy credit. Available at: http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA-partIV-subpartE-sec48.pdf

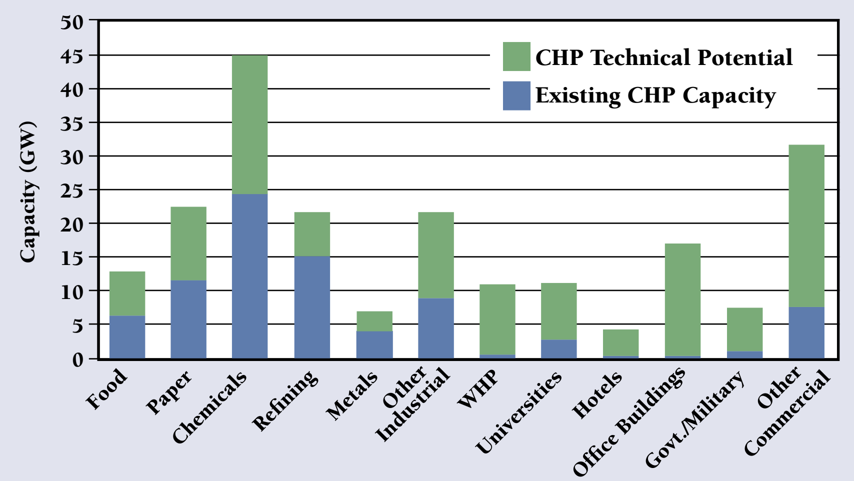
11 Heat Is Power. (2014). *Waste Heat to Power Fact Sheet.* Available at: http://www.heatispower.org/wp-content/uploads/2014/10/HiP-WHP-Fact-Sheet-10-23-2014.pdf

combined with the fuel's low-emissions profile, positions it as a driving force in CHP growth.

CHP technology is largely mature, which makes it deployable over the near-term at existing facilities and gives it the potential to play an important role at various scales in replacing industrial and commercial coal-fired boilers as they move toward retirement.[12] Accounting for 8 percent of current US generating capacity and 12 percent of electricity, CHP is regarded as an underutilized opportunity for emissions reductions.[13] ICF International estimates there to be a total of 125 gigawatts (GW) of remaining technical potential for CHP at existing industrial and commercial/institutional facilities across the United States (Figure 3-2).[14] A separate research effort in 2008 by Oak Ridge National Laboratory (ORNL) analyzed a goal of increasing CHP to 20 percent of generation capacity by 2030. It found that achieving 20-percent CHP would substantially reduce national energy consumption, saving 5.3 quadrillion BTU of fuel annually, the equivalent of nearly half the total energy consumed currently at the residential level.[15]

Figure 3-2

CHP Technical Potential and Existing Capacity by Sector[16]



Source: ICF Internal Projections

2. Regulatory Backdrop

A map of CHP facilities in the United States prepared by the US Energy Information Administration, shown in Figure 3-3, illustrates that US CHP capacity is geographically concentrated and that there are two kinds of conditions in which CHP has taken hold. One condition is where the economics strongly support mid- to larger-scale applications, such as in the petrochemical and refineries of the Gulf Coast (where Texas and Louisiana alone account for 30 percent of national CHP capacity), as well as in timber-rich states in the Southeast, Northwest, and in Maine, where the residual wood waste stream provides cheap boiler fuel in the pulp and paper industry (paper production accounts for 14 percent of national capacity). Large cities in the north are another example where geographic circumstances facilitate the economics of district heating and cooling. The other parts of the country where CHP shows high levels of penetration are in states, such as California (8.8 GW) and New York (5.5 GW), that have high electricity prices and have fostered favorable regulatory environments for CHP.[17] This highlights the extent to which policy is integral to creating or removing barriers to CHP.

12 Chittum, A. (2012, September). *Coal Retirements and the CHP Investment Opportunity.* Available at: http://www.aceee.org/research-report/ie123

13 ICF International for US Department of Energy and ORNL, at supra footnote 5.

14 Note that technical potential is not the same as economic potential. Technical potential accounts for sites that have electric and thermal demands suitable to CHP, while ignoring economic considerations. ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States.* Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx

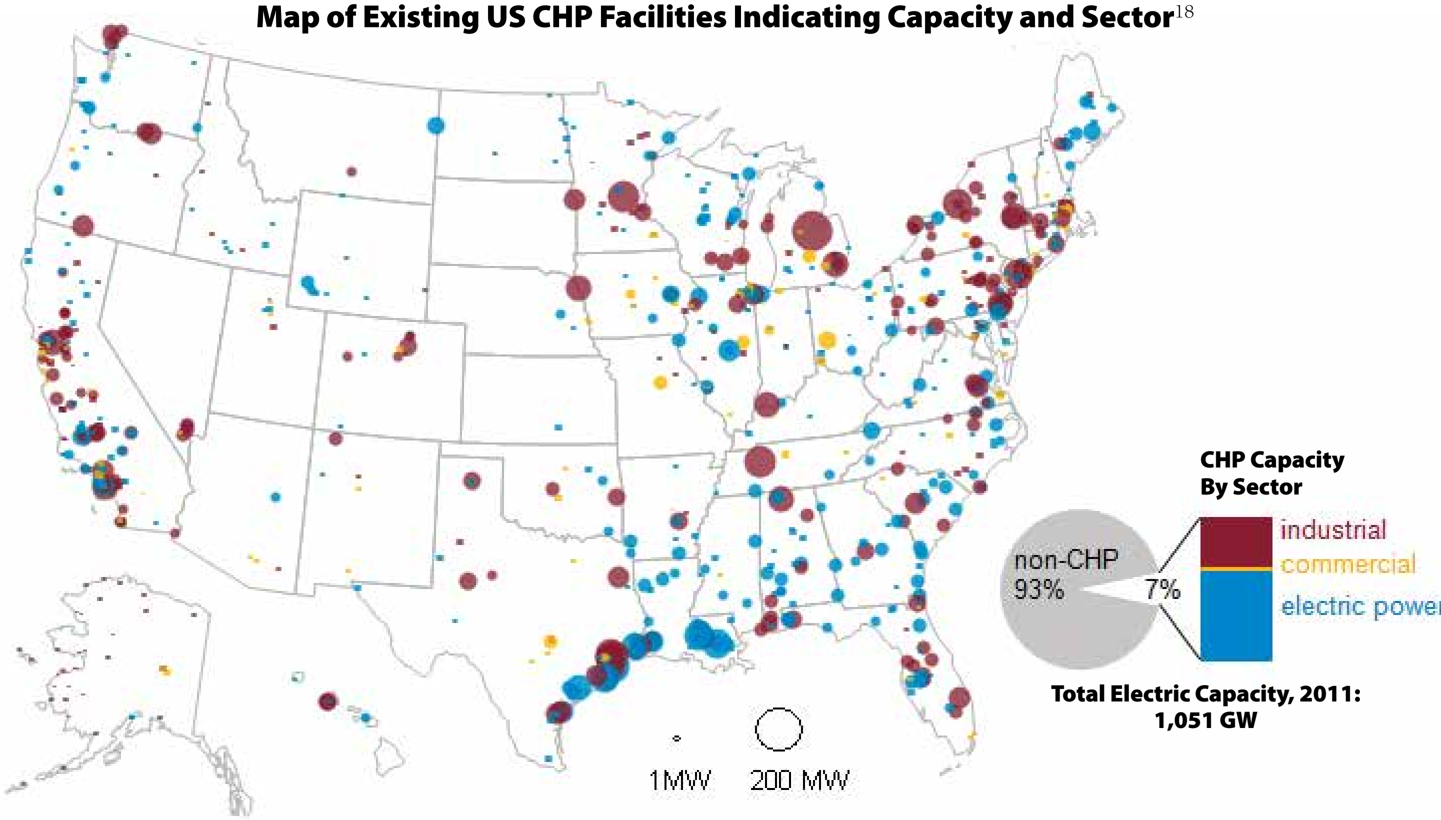
15 Shipley, A., Hampson, A., Hedman, B., Garland, P., & Bautista, P. (2008, December 1). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* ORNL for US Department of Energy. Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf

16 ICF International. (2014, July 23). *From Threat to Asset: How Combined Heat and Power Can Benefit Utilities.* Available at: http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities?_cldee=amVubmlmZXJAZGdhcmRpbmVyLmNvbQ%253d%253d&utm_source=ClickDimensions&utm_medium=email&utm_campaign=Com%253A%20Energy_Webinar_07.08.14

17 ICF International for US Department of Energy and ORNL, at supra footnote 5.

Figure 3-3

Map of Existing US CHP Facilities Indicating Capacity and Sector[18]



Given the diversity of technologies, fuels, sizes, and sectors, the regulatory context surrounding CHP is multifaceted. The following discussion focuses on a number of regulatory drivers currently affecting CHP, namely:

- Issues in utility regulation;
- Air pollution regulations;
- National and state CHP capacity targets; and
- Grid reliability and resilience.

Utility Regulation

Federal and state utility regulation has played a major part in promoting CHP in the industrial, commercial, and institutional sectors. Many of the barriers facing CHP pertain to economies of scale and the technical and administrative burdens facing small power producers who are usually not in the energy business. The Federal Public Utilities Regulatory Policies Act (PURPA) of 1978 had the effect of encouraging CHP by obligating utilities to buy power from independent CHP generators meeting certain eligibility standards. PURPA also requires utilities to pay prices equivalent to the utilities' avoided cost, and to offer reasonable standby rates and backup fees.[19] These rules, in conjunction with federal tax credits initiated in 1980, had the effect of stimulating investment in CHP, which increased five-fold from 1980 through 2000 (refer to Figure 2-4 in Chapter 2).

Following the development of competitive wholesale power markets in parts of the country, the Federal Energy Regulatory Commission (FERC) issued rulings pursuant to the Energy Policy Act of 2005, which exempts utilities from the PURPA must-buy provisions for larger facilities (>20 MW) in cases in which the facility has non-discriminatory access to wholesale markets.[20] This amendment, along

18 US Energy Information Administration. (2012, October). *Today in Energy: Combined Heat and Power Technology Fills an Important Energy Niche.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=8250

19 Avoided cost is defined as the cost of energy that would have been supplied from the utility's own system if the energy had not been supplied by the qualifying facility.

20 US FERC. (2006, October 20). Ruling No. 688. New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities. Available at: https://www.ferc.gov/whats-new/comm-meet/101906/E-2.pdf. All related orders by FERC pertaining to Qualifying Facilities can be found at: https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders.asp

with volatile natural gas prices and general regulatory uncertainty surrounding the establishment of competitive markets, spawned a period starting in 2006 of steep decline in new CHP capacity additions.[21]

Today, PURPA is implemented variably across the country. Interconnection standards, standby rates, and tariffs are still considered regulatory obstacles to greater deployment of CHP. Although financial incentives are part of the problem, low rates of technology adoption are also attributed to administrative burdens surrounding grid interconnection. A 2013 report by the State and Local Energy Efficiency Action Network (SEE Action) provides a thorough survey of the regulatory architecture needed to support CHP deployment, including detailed recommendations on the following issues:[22]

- **Interconnection Standards.** CHP and other distributed generation resources can be facilitated through standardized interconnection rules and streamlined application procedures. Standard guidelines of some kind are in place in 43 states and the District of Columbia.[23]
- **Rates for Standby Services.** Utilities charge CHP customers standby tariffs in exchange for providing a bundle of services that includes back-up power for unplanned outages and scheduled maintenance, supplemental power for customers for whom onsite generation is insufficient, and the associated transmission and distribution delivery services, among other offerings. Originally designed in a vertically integrated electricity market with few interties, standby rates were averaged over customer classes. Today rates may be structured to more closely match actual costs incurred based on individual customer profiles.[24] They can also be accompanied by requirements and incentives that encourage customer-generators to use electric services efficiently and minimize costs on the grid.[25]
- **Prices Paid for Excess Electricity.** Avoided cost rates implemented through PURPA, Feed-In Tariffs (FITs), and competitive procurement have all been demonstrated to be effective methods for setting prices for electricity delivered to the grid from CHP systems. FERC recently ruled that the value of a resource in helping to meet state procurement obligations (i.e., renewable portfolio standards) can be incorporated into avoided cost calculations.[26] This ruling dealt specifically with California's "multi-tiered" avoided cost rate structure for a FIT to acquire smaller CHP systems (<20 MW), which FERC found to be consistent with PURPA. Usually FITs set a fixed price per unit delivered from a specific energy technology type (e.g., wind, solar, CHP) over a set period of years. Such pricing is based on the estimated cost of eligible generation plus a reasonable return to investors, but FIT prices can also be based on the value the generator provides to the electric system. Alternatively, in a restructured environment, CHP projects may bid into energy, capacity, and ancillary service markets if they meet established protocols, and a FIT may take the form of a premium payment on top of the energy market price. In jurisdictions with CHP targets, competitive procurement processes are also used to reveal costs and acquire larger projects.[27]

21 US Department of Energy and US EPA. (2012, August). *Combined Heat and Power: A Clean Energy Solution.* Available at: http://www.epa.gov/chp/documents/clean_energy_solution.pdf

22 US Department of Energy, US EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies

23 For more on best practices in design of interconnection standards, see: Sheaffer, P. (2011, September). *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4572

24 The Regulatory Assistance Project. (2014, February). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States.* Available at http://www.raponline.org/press-release/standby-rates-for-combined-heat-and-power-need-a-fresh. Johnston, L., Takahashi, K., Weston, F., & Murray, C. (2005, December). *Rate Structures for Customers With Onsite Generation: Practice and Innovation.* NREL/SR-560-39142. Available at: http://www.michigan.gov/documents/energy/NREL_419830_7.pdf

25 For more detail and specific case studies, consult The Regulatory Assistance Project's policy brief outlining standby rate design features to support CHP systems, at supra footnote 24. Also see: ACEEE. *Policies and Resources for CHP Deployment: CHP-Friendly Standby Rates.* Available at: http://aceee.org/policies-and-resources-chp-deployment-chp-friendly-standby-rates

26 US FERC. (2010). 133 FERC ¶ 61,059. Available at: https://www.ferc.gov/whats-new/comm-meet/2010/102110/E-2.pdf

27 Supra footnote 22.

Air Pollution Regulations

In Chapter 2, a list of existing and proposed federal New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants (NESHAP) that might impact CHP installations was provided. The applicability of each regulation depends on the fuels combusted, the heat input or electrical output of the system, how much electricity is delivered to the grid versus used onsite, and the date of construction, reconstruction, or modification.

As noted in Table 3-1, most of the installed CHP capacity in the United States uses either steam turbine or gas combustion turbine technology. Furthermore, most of the CHP units described in this chapter do not meet the definition of electric utility steam generating unit because they are designed to generate electricity for onsite consumption, and therefore are not directly affected by regulations for electric generating units such as the proposed GHG regulations under sections 111(b) and 111(d) of the Clean Air Act. Thus, the regulations most relevant to the CHP units described in this chapter are the NESHAP regulations for industrial, commercial, and institutional boilers and process heaters (40 CFR Part 63 Subparts DDDDD and JJJJJ) and for stationary combustion turbines (Subpart YYYY), as well as the New Source Performance Standards regulations for industrial, commercial, and institutional steam generating units (40 CFR Part 60 Subparts Db and Dc) and for stationary combustion turbines (Subpart KKKK). New Source Review (NSR) permitting requirements are also significant.

Finalized in January 2013, the NESHAP for new and existing boilers and process heaters covers major sources in industrial, institutional, and commercial facilities.[28] These Maximum Achievable Control Technology (MACT) standards, commonly called the "Boiler MACT," affect roughly 14,000 boilers across the country, burning a wide range of fuels and providing heat for various mechanical, heating, and cooling processes and uses.[29] Relatively few of these boilers already use CHP technology, but the impact of the regulations on CHP deployment may be much more significant. Notably, the Boiler MACT rule includes provisions that reward energy efficiency upgrades, such as investments in waste heat recovery and CHP. All existing major sources in this source category are required to do routine tune-ups and to conduct a one-time energy assessment to identify cost-effective conservation measures.

The Boiler MACT rules also set specific emissions limits for some 1750 of the largest industrial boilers, fired primarily by coal, oil, and biomass.[30] Facilities can opt to use output-based emissions limits instead of heat input-based limits. These standards are set in terms of pounds of pollution per million BTU of steam output (lb/MMBTU) and pounds of pollution per megawatt-hour of electricity output (lb/megawatt-hour [MWh]), rather than pounds of pollution per million BTU of heat input. Using the output-based standards allows firms to earn credit toward compliance because their implementation of boiler efficiency measures has the effect of reducing energy input relative to a constant level of useful output.[31] But with many of these boilers more than 40 years old,[32] owners have also evaluated options for boiler replacement, creating a timely window for new CHP installations. Subject to a January 21, 2016 deadline, compliance decisions — whether to upgrade coal boilers, convert or replace natural

28 40 CFR Part 63. (2013, January 31). *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.* Available at: http://www.gpo.gov/fdsys/pkg/FR-2013-01-31/pdf/2012-31646.pdf. A major source facility emits or has the potential to emit 10 or more tons per year of any single air toxic or 25 or more tons per year of any combination of air toxics. Sources that emit less than this threshold are classified as area sources.

29 US EPA. (2012, December). *EPA's Air Toxics Standard Major and Area Source Boilers and Certain Incinerators: Technical Overview.* Available at: http://www.epa.gov/airquality/combustion/docs/20121221_tech_overview_boiler_ciswi_fs.pdf

30 US EPA. *Emissions Standards for Boilers and Process Heaters and Commercial/Industrial Solid Waste Incinerators.* Available at: http://www.epa.gov/airquality/combustion/actions.html

31 Federal Register Section 63.7533 outlines the methodology for determining compliance using emissions credits and the EPA provides a hypothetical example online here: http://www.epa.gov/ttn/atw/boiler/imptools/energycreditsmarch2013.pdf

32 Nearly half of the US boiler population with a capacity greater than 10 MMBTU/h is at least 40 years old. Energy and Environmental Analysis for ORNL. (2005). *Characterization of the US Industrial/Commercial Boiler Population.* Available at: http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/characterization_industrial_commerical_boiler_population.pdf

gas boilers, or switch to natural gas CHP — have largely been made and are being implemented now. This rule demonstrates how environmental regulations can drive markets for energy-efficient technologies like CHP, even while regulating emissions from CHP systems.

The rule also offers a model for how government can assist in promoting the benefits of CHP. Through the seven regional offices of its CHP Technical Assistance Partnerships,[33] the US Department of Energy (DOE) takes advantage of this Boiler MACT compliance opportunity by providing general outreach and market research, as well as site analysis to support CHP project development from feasibility to installation.[34] Outreach to nearly 700 facilities returned interest from 50, representing a potential of 752 MW of CHP capacity additions.[35] Focused on strategic markets, including hospitals, critical infrastructure, biomass, district microgrids, and federal agencies, the DOE's program has sought to develop examples with broader implications for adopting CHP in conjunction with environmental compliance activities. As part of the program, the DOE has produced a number of reports and resources, including a 2012 report prepared by ICF International enumerating financial incentives state by state[36] and a guidance document prepared by ORNL for calculating emissions credits from conservation measures.[37]

CHP applications reduce the total amount of pollution emitted onsite and offsite, yet by generating heat and power onsite they may have the effect of increasing a facility's direct onsite emissions. In this way, accounting for the benefits of CHP requires an outside-the-fence approach, which has posed a challenge to energy and environmental regulations conventionally focused on fuel-use and pollution at individual facilities within individual source categories. The NSR program illustrates this problem.[38]

The NSR permitting process, which may be triggered if modifications to an industrial plant are expected to increase onsite pollution, often requires expensive investments in end-of-pipe pollution controls for facilities seeking to make capital upgrades for CHP. Further challenging conventional regulation is the fact that a CHP facility produces multiple value streams: thermal energy, electric energy, and electricity demand reductions through energy efficiency. Especially given the diverse range of applications, sizes, and fuel types, the issue of how to quantify these values and how to regulate CHP more generally has long been problematic.

The shift in state and federal regulatory strategies over recent years from input-based to output-based regulations (OBR) helps remedy this problem.[39] OBRs, framed as pollution per unit of productive output, encourage clean energy deployment and help incorporate energy efficiency and renewable energy investments directly as compliance options, while granting businesses the opportunity to flexibly achieve the emissions limits through various means, including heat rate improvements, cleaner fuel substitutes, or end-of-pipe technologies. Output-based emissions standards can be applied to any process to promote efficiency. The recently finalized New Source Performance

33 The DOE's CHP Technical Assistance Partnerships (CHP TAPs) were formerly called the Clean Energy Application Centers (CEACs). Available at: http://www1.eere.energy.gov/manufacturing/distributedenergy/chptaps.html

34 US DOE. *Boiler MACT Technical Assistance Program.* Available at: http://energy.gov/eere/amo/boiler-mact-technical-assistance-program. Starting in February of 2012, an initial pilot effort between the DOE and the Ohio Public Utility Commission was subsequently scaled to the national level. Public Utilities Commission of Ohio. *Combined Heat and Power in Ohio.* Available at: http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/combined-heat-and-power-in-ohio/

35 US DOE. (2014, May). *Boiler MACT Technical Assistance.* Available at: http://energy.gov/sites/prod/files/2014/05/f15/boiler_MACT_tech_factsheet_1.pdf. Hampson, A. (2014). Presentation at the Electric Power Conference and Exhibition. *CHP Market Status and Opportunities for Growth*. ICF International.

36 ICF International for US DOE. *Financial Incentives Available for Facilities That are Affected by the US EPA NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters: Proposed Rule.* Available at: http://www1.eere.energy.gov/manufacturing/states/pdfs/incentives_boiler_mact.pdf

37 ORNL. (2012). *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers, Guidance for Calculating Emission Credits Resulting from Implementation of Energy Conservation Measures.* Available at: http://info.ornl.gov/sites/publications/Files/Pub37258.pdf

38 US EPA. (2013, July 30). *New Source Review.* Available at: http://www.epa.gov/NSR/

39 US EPA CHP. (2014). *Output-Based Regulations: A Handbook for Air Regulators.* Available at: http://www.epa.gov/chp/documents/obr_handbook.pdf

Standards for Electric Utility Steam Generating Units, for example, include output-based emissions standards for particulate matter, nitrogen oxides (NO_X), and sulfur dioxide (SO_2).[40]

OBRs are especially useful in addressing sources that have more than one productive output. A 2013 EPA guidance document on "Accounting for CHP in Output-Based Regulations" recommends two approaches for incorporating a secondary output into emissions rate calculations.[41] The first is an *equivalence approach,* whereby the secondary output — be it electricity or thermal energy, depending on the configuration — is converted into the units of the primary output by way of a conversion factor. The conversion factor may be a direct unit conversion (e.g., 3.412 MMBTU/MWh) or may reflect a certain valuation of the secondary energy output by discounting as per regulatory objectives. This method has been used by the state of Texas in its permit by rule and standard permit regulations, and in California in its conventional emissions limits and emissions performance standards for CHP.[42]

Alternatively, the EPA outlines an *avoided emissions approach,* which involves developing assumptions about the pollution that would have been emitted if the same outputs had been generated separately.[43] Offset emissions are subtracted from the CHP system's actual emissions to capture its offsite benefits. OBRs thus could specify the default assumptions, for example, *Avoided Thermal Efficiency* would typically be based on the performance of a new natural gas-fired boiler (80 percent) and the Avoided Central Station Emission Factor would be based on fleet data from the EPA's Emissions & Generation Resource Integrated Database (eGRID) database. Connecticut and Massachusetts are using avoided emissions methods in accounting for small distributed generation; Delaware and Rhode Island have also used this approach in conventional emissions limits for CHP.[44]

These two approaches for incorporating a secondary output into emissions rate calculations are described in greater detail in Chapter 2. There is some controversy about which method is most appropriate for regulatory purposes. Although both methods reward efficiency, there is general consensus that quantifying avoided emissions produces a more accurate emissions signature of a CHP system, yet the equivalence method has been preferred historically for its simplicity. Within the equivalence method there is additional debate over the conversion factor. Historically, the EPA has discounted thermal energy 50 percent in OBRs, whereas California and Texas are states that ascribe 100 percent credit for thermal output in their OBRs. In its recent proposal to regulate GHG emissions from existing EGUs [under section 111(d)], the EPA assigned a value of 75 percent credit and requested comment on a range of two-thirds to 100-percent credit for useful thermal output.[45] The same regulatory proposal further rewards CHP by applying an additional five percent line loss credit to the net electric output to capture the transmission and distribution losses that are avoided through onsite power generation.

Capacity Targets

In 2012, the Obama Administration set a national goal of 40 GW of new, cost-effective CHP by 2020 through an Executive Order to Accelerate Investment in Industrial Energy Efficiency.[46] This has helped to motivate greater coordination of existing federal activities on the issue, predominantly between the EPA and the DOE. The SEE

40 40 CFR Part 60, Subpart Da. *Standards of Performance for Electric Utility Steam Generating Units.* Available at: http://www.ecfr.gov/cgi-bin/text-idx?SID=324a6cdb45a7b9a1f8c055dc6e64982d&node=sp40.7.60.d_0a&rgn=div6

41 US EPA CHP Partnership. (2013, February). *Accounting for CHP in Output-Based Regulations.* Available at: http://www.epa.gov/chp/documents/accounting.pdf.

42 Ibid.

43 The Regulatory Assistance Project. (2003). *Output Based Emissions Standards for Distributed Generation.* Available at: http://www.raponline.org/docs/RAP_IssuesLetter-OutputBasedEmissions_2003_07.pdf

44 Supra footnote 41. Other examples can be found in Appendix B of the EPA's 2003 handbook for air regulators on output-based regulations, at supra footnote 39.

45 79 FR 34829. Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

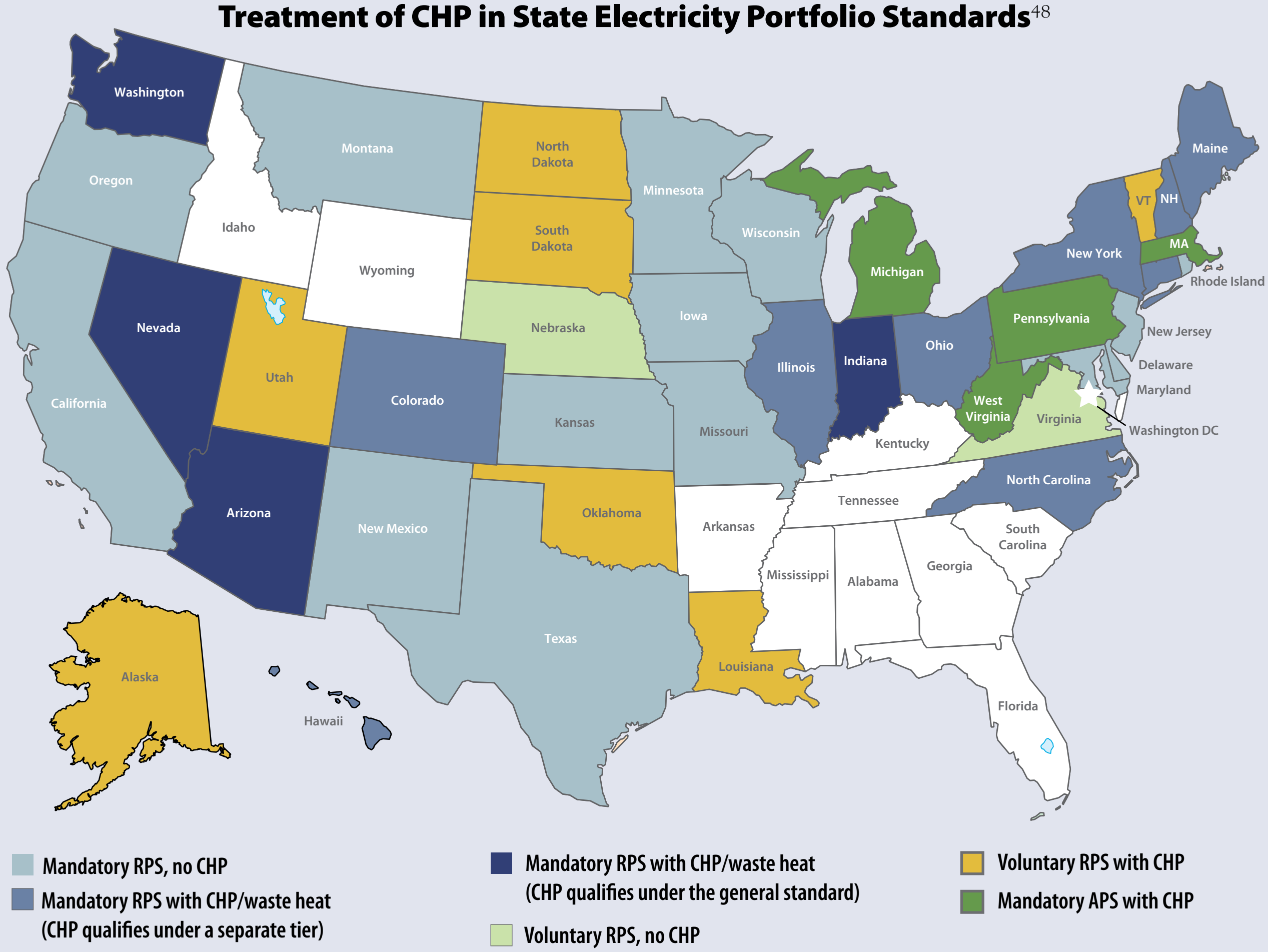
46 Executive Order 13624. (2012, August 30). *Accelerating Investment in Industrial Energy Efficiency.* 77 FR 54779. Available at: http://www.gpo.gov/fdsys/pkg/FR-2012-09-05/pdf/2012-22030.pdf

Action Network has taken the lead, convening stakeholders and providing technical assistance to states. Many resources related to these efforts can be found on SEE Action's website, the EPA's website for its Combined Heat and Power Partnership program, and the DOE's website for CHP Deployment and Technical Assistance Partnerships.[47]

A number of states have supported CHP through portfolio standards. Portfolio standards require electric utilities and retail providers, often through legislation, to meet a certain portion of load with specified clean energy resources. As of 2013, 23 states include CHP in either energy efficiency or renewable energy portfolio standards (Figure 3-4). Energy efficiency portfolio standards are discussed in detail in Chapter 11, and renewable portfolio standards are the focus of Chapter 16. These programs are typically designed to allow eligible projects to generate credits, the sale of which adds a stream of revenue for project finance. However, the terms of eligibility vary across states, often reflecting narrow definitions of CHP that, for example, capture only bottoming-cycle (WHP) or renewable fuel-powered configurations. Where portfolio standards have been more effective at incentivizing investment, they have clearly defined CHP, defined it broadly enough to include fossil fuels, established minimal efficiency requirements (i.e., minimum 60 percent annual combined electric and thermal efficiency with fuel input

Figure 3-4

Treatment of CHP in State Electricity Portfolio Standards[48]



Source: Map based on ICF International research. December 2012.

47 US DOE, US EPA, & SEE Action Network. Available at https://www4.eere.energy.gov/seeaction/. US EPA CHP Partnership. Available at: http://www.epa.gov/chp/. US DOE CHP Deployment. Available at: http://energy.gov/eere/amo/chp-deployment

48 Supra footnote 22.

expressed on a higher heating value basis), and set dedicated CHP targets as a distinct class of resources.

Specific CHP targets have also been enacted through broader legislation and/or issued executive orders in some states. California, for example, established a goal of 6500 MW of new CHP through executive order. New Jersey set a target of 1500 MW of new CHP capacity through its Energy Master Plan.[49]

Grid Reliability and Resiliency

CHP has also been noted for its ability to strengthen grid reliability and improve the resiliency of critical infrastructure. The events of September 11, 2001, the Northeast blackout in 2003, Hurricane Katrina in 2005, and Superstorm Sandy in 2012, among other disasters, have underscored the importance of having independent and reliable power supply for critical infrastructure, such as hospitals, public safety facilities, emergency response communications, and care centers for elderly and other vulnerable populations. CHP has been demonstrated to provide reliability over both instantaneous outages as well as prolonged outages,[50] and systems can be designed to meet power needs more adequately —that is, more seamlessly, at lower cost, and with lower environmental impacts — than traditional backup generators. In the wake of the storms of 2011 and 2012, New York, New Jersey, and Connecticut adopted CHP incentive programs designed to enhance resiliency for disaster response and preparedness.[51] Texas and Louisiana have laws requiring critical government buildings to undertake feasibility studies for implementing CHP.[52,53]

3. State and Local Implementation Experiences

Examples can be found across the country of CHP units that are designed primarily to meet onsite or nearby energy needs, rather than to supply electricity to the grid. These examples include CHP systems owned by state or municipal governments, universities, hospitals, manufacturers, and others. Case studies featuring certain aspects of the policy and regulatory context are enumerated in many of the reports cited earlier, especially The Regulatory Assistance Project (2014), SEE Action (2013), and ICF (2013). The Database of State Incentives for Renewables and Efficiency, which is currently run out of North Carolina State University, provides an online database of CHP policies searchable by type and state; the EPA maintains a similar database.[54] Additional examples are provided in Chapter 2.

CHP projects can be built with the help of public policies and incentives, yet fail to achieve the high efficiency goals anticipated from the technology. Proper sizing for the project demand, engineering, construction, and operation are all critical to a project attaining its goals, and relatively minor variations can have significant impact. Studies that included efficiency evaluations for a number of completed CHP projects in California and New York indicated that the operating efficiencies of some projects were far below expectations and similar to non-CHP EGUs. To ensure accountability for public funds and emissions reductions, incentives programs should be linked to project performance. An example comes from New

49 The Industrial Energy Efficiency and Combined Heat and Power Working Group of the SEE Action Network released a “Guide to the Successful Implementation of State Combined Heat and Power Policies” in 2013, which details options and case studies for effective support of CHP through portfolio standards-like tools. Supra footnote 22.

50 ACEEE. (2012, December 6). *How CHP Stepped Up When the Power Went Out During Hurricane Sandy.* Available at: http://www.aceee.org/blog/2012/12/how-chp-stepped-when-power-went-out-d

51 CT P.A. 12 148 Section 7. (2012, July). *Microgrid Grant and Loan Pilot Program.* Available at: http://www.cga.ct.gov/2012/act/pa/pdf/2012PA-00148-R00SB-00023-PA.pdf

52 Texas HB 1831. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB01831F.pdf. Texas HB 4409. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB04409F.pdf. Louisiana Senate resolution No. 171. (2012). Available at: http://www.legis.la.gov/legis/BillInfo.aspx?s=12RS&b=SR171&sbi=y

53 For more extensive information on case studies, see: ICF International for ORNL. (2013, March). *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* Available at: http://energy.gov/eere/amo/downloads/chp-enabling-resilient-energy-infrastructure-critical-facilities-report-march

54 Database of State Incentives for Renewables & Efficiency. Available at: http://www.dsireusa.org/; US EPA. (2014, August). *CHP Policies and Incentives Database.* Available at: http://epa.gov/chp/policies/database.html

York State Energy Research and Development Authority's CHP performance program, in which projects are subject to measurement and verification procedures and the incentive payment schedule is contingent on monitored performance.[55]

For the purposes of this document, the implementation experiences of the state of Massachusetts are presented in greater detail to illustrate the components of a cohesive state policy in support of CHP.

In 2008, Massachusetts started what has become a concerted push to develop CHP using two main policy vehicles. The first is the utility energy efficiency program called "Mass Save," mandated by the Green Communities Act of 2008 (S.B. 2768), and launched in 2011.[56] The program is funded through: (1) a system benefit charge on electricity use; (2) an energy efficiency reconciliation factor on electricity distribution rates; (3) proceeds from the Regional Greenhouse Gas Initiative; and (4) the New England Independent System Operator's (ISO) Forward Capacity Market.[57] Mass Save provides incentive rebates to residential, commercial, and industrial customer classes for energy efficiency investments, including CHP.

Eligible CHP must pass a benefit-cost ratio (BCR) test, whereby the lifetime benefits are greater than or equal to lifetime costs (i.e., BCR ≥1). The BCR model captures societal value by incorporating:

- Annual power output (net kW);
- Electricity output (net kilowatt-hour [kWh]);
- Installed cost of equipment;
- Annual maintenance costs;
- Quantity and type of fuel consumed and displaced; and
- The timing of power production (i.e., peak/off-peak, summer/winter).

The model uses marginal values for fuel and electricity and the value of deferred transmission and distribution, according to the peak period terms of the ISO of New England.[58]

Qualifying retrofit projects earn rebates based on where the project fits within three tiers of efficiency performance. At the low end of the scale, Tier 1 can earn up to $750/kW. At the high end, Tier 3 can earn up to $1100/kW ($1200/kW for projects <150 kW). The grant of a rebate is contingent on:

- Achieving a system efficiency of greater than 65 percent;
- Undertaking an ASHRAE Level 2 Audit;[59] and
- Implementing efficiency measures to reduce overall energy use at the facility by ten percent within three years.

New construction projects are eligible for a rebate of $750/kW that can be increased on a case-by-case basis, contingent on a project achieving the 65-percent efficiency threshold and implementing additional energy efficiency measures.[60]

A November 2013 review of Mass Save's CHP program found that it had been successful, with high realization rates, accounting for 30 percent of commercial and institutional energy efficiency target savings in 2011. CHP was also found to deliver the lowest cost per kWh of all Mass Save measures.[61] Because proper sizing of a CHP system is essential to its cost-effectiveness, one key lesson learned in Massachusetts has been that reducing load through energy efficiency needs to be the first step in determining the appropriate size and design of a CHP system.[62] This is partly why providing incentives for CHP based on efficiency performance has proved to be so successful.

55 New York State Energy Research and Development Authority. (2015, January). *Combined Heat and Power Performance Program.* Available at: http://www.nyserda.ny.gov/All-Programs/Programs/Combined-Heat-and-Power-Performance-Program

56 Mass Save public website. Available at: http://www.masssave.com/

57 Mass Save. (2012, November). *2013-2015 Massachusetts Joint Statewide Three Year Electric and Gas Energy Efficiency Plan.* Available at: http://www.mass.gov/eea/docs/doer/energy-efficiency/statewide-electric-and-gas-three-year-plan.pdf

58 Mass Save. (2014, May 27). *Combined Heat and Power: A Guide to Submitting CHP Applications for Incentives in Massachusetts.* Available at: http://www.masssave.com/~/media/Files/Business/Applications-and-Rebate-Forms/A-Guide-to-Submitting-CHP-Applications-for-Incentives-in-Massachusetts.pdf

59 See Chapter 15 for a discussion of ASHRAE building energy codes.

60 Supra footnote 58.

61 US DOE/IIP Webinar. (2013, November 20). *Massachusetts Incentives for Combined Heat and Power: Mass Save Energy Efficiency and the Alternative Portfolio Standard.* Dwayne Breger, Director, Renewable Energy Division, Massachusetts Department of Energy Resources. Available at: https://cleanenergysolutions.org/webfm_send/964

62 Supra footnote 57.

The second major policy vehicle supporting CHP in Massachusetts is the state's Alternative Energy Portfolio Standard (APS), which puts an obligation on retail electricity suppliers to acquire Alternative Energy Certificates (AECs) equal to a set percentage of served load. Established pursuant to the 2008 Green Communities Act[63] and administered under the Alternative Energy Portfolio Standard Regulation,[64] compliance obligations began in 2009, requiring one percent of retail sales to come from qualifying energy sources, a level that increases to five percent by 2020. The APS covers a range of nonrenewable technologies, including flywheel energy storage, CHP, and renewable thermal technologies, but as of 2013, nearly all AECs were generated from CHP projects.[65]

The APS complements the Mass Save rebate program. While the latter defrays upfront capital costs, the APS rewards metered performance. CHP units are responsible for metering both thermal and electricity output, as outlined in the APS metering guidelines,[66] where credits are earned based on fuel savings compared to grid power and a separate thermal conversion unit. AECs are calculated as follows:

> The number of Credits = (electricity generated/0.33) + (useful thermal energy output/0.8) – (total fuel consumed by the CHP unit), where all quantities are expressed in MWh.

Massachusetts uses an Alternative Compliance Payment (ACP) mechanism as a price ceiling. The ACP was set at $21.72 per MWh for the 2014 compliance year.[67] In 2013, for example, earned credits fell short of the 1448 gigawatt-hours required to meet the three-percent obligation on utilities for that year. As a result, some 64 percent of the obligation was met through ACPs, totaling nearly $19.8 million[68] — revenues that were recycled back into clean energy initiatives through the Commonwealth's Department of Energy Resources.[69] The supply of credits follows the pace of project approval through the Mass Save rebate program, such that as the number of certified projects grow and with several large projects in the pipeline, the supply of AECs is expected to increase. As of 2014, 329 MW of CHP capacity was either approved or was under review through the APS program.[70]

One example of a successfully supported project highlighted by the Department of Energy Resources was installed on the campus of the University of Massachusetts Medical School. There, a 7.5-MW expansion to the existing 9-MW cogeneration facility boosted overall efficiency from 71 percent to 86 percent, resulting in an annual reduction in GHG emissions of 19 percent. The project was awarded $5.6 million through Mass Save, the equivalent of 20 percent of capital expenditure,[71] and is projected to earn 135,488 credits through the Alternative Portfolio Standard,

63 Part 1, Title II, Chapter 25A, Section 11F1/2. Alternative Energy Portfolio Standard. Available at: http://www.malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter25A/Section11F1~2

64 Code of Massachusetts Regulation. 225 CMR 16.00. Alternative Energy Portfolio Standard. Available at: http://www.mass.gov/eea/docs/doer/rps/225cmr1600-052909.pdf

65 Massachusetts Department of Energy Resources. (2014, December 17). *Massachusetts RPS & APS Annual Compliance Report for 2013.* Available at: http://www.mass.gov/eea/docs/doer/rps-aps/rps-aps-2013-annual-compliance-report.pdf

66 Massachusetts Department of Energy Resources. (2011, June 14). *APS Guideline on the Eligibility and Metering of Combined Heat and Power Projects.* Available at: http://www.mass.gov/eea/docs/doer/rps-aps/aps-chp-guidelines-jun14-2011.pdf

67 Massachusetts, Executive Office of Energy and Environmental Affairs. (2014, August). *Alternative Compliance Payment Rates.* Available at: http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/retail-electric-supplier-compliance/alternative-compliance-payment-rates.html

68 Subject to increases with the consumer price index. Supra footnote 65.

69 Massachusetts Department of Energy Resources. (2014, December 17). *CY 2013 Alternative Compliance Payments – Spending Plan.* Available at http://www.mass.gov/eea/docs/doer/rps-aps/cy-2013-acp-spending-plan.pdf

70 Massachusetts Department of Energy Resources. *APS Qualified Generation Units – Updated May 1, 2014.* Available at: http://www.mass.gov/eea/docs/doer/rps-aps/aps-qualified-units.xls

71 Sylvia, M. (2013, June 26). *Clean Energy Opportunities in Massachusetts.* Presentation before the Juniper Networks Energy Summit. Massachusetts Department of Energy Resources. Available at: http://competitive-energy.com/CES_JuniperNetworksSummit_MADOER_Presentation_062613.pdf

equivalent to more than $2.9 million of annual revenue.[72]

Massachusetts further enables CHP development by providing standardized application procedures and contracts for grid interconnection overseen by the Massachusetts Department of Public Utilities. These procedures apply uniformly across the state's four investor-owned utilities. They offer generator customers transparent rules for expeditious interconnection, while ensuring the safety and reliability of the grid. The model interconnection tariff provides three different review paths based on the complexity of the project, that is, generation type, size, customer load, and the characteristics of the grid where the system is to be located. The "Simplified and Expedited" review paths are designed to streamline projects that pass pre-specified screening tests, whereas the "Standard" path is reserved for all other projects in which system modifications may be required to accommodate the project. These procedures were most recently amended in July 2014 with Order 11-75-F to assign an enforceable timeline for interconnections.[73] Interconnection activity is reported monthly and made available online to give customers a clearer understanding of expectations for the interconnection process.[74]

4. GHG Emissions Reductions

A CHP system can reduce CO_2 emissions roughly 50 percent compared to separate heat and power systems, as shown in Figure 3-1, by reducing fuel consumption. Emissions of other GHGs may also be reduced, including methane, nitrous oxide, precursors to ground-level ozone, and particulate pollution, which can also interact with the climate. The 2008 report by ORNL cited previously in this chapter analyzed a goal of increasing CHP to 20 percent of generation capacity by 2030. It found that achieving 20-percent CHP would reduce CO_2 emissions by more than 800 million metric tons per year, equivalent to 60 percent of projected growth in emissions over that time period.[75] These results echo those of numerous other studies that have shown that CHP is one of the most cost-effective strategies for reducing CO_2 emissions economy-wide.

It is important to note that CHP may not always be an appropriate strategy for reducing carbon emissions. In parts of the country with low GHG electricity, like the gas-dominated grid in California, CHP emissions could conceivably exceed those of separate heat and power. To account for this, eligibility for incentives typically includes threshold efficiency rates, but could also be structured to reward only net-GHG-reducing facilities.

Estimates of CO_2 emissions reductions associated with CHP systems are derived from fuel savings. Calculating fuel savings associated with a CHP system uses a similar methodology to the avoided emissions approach described previously. The fuel used onsite is deducted from the displaced fuel that would have been used for separate production of thermal and electric energy, including transmission and distribution losses, according to the basic series of equations included below.[76]

The first step is to calculate emissions displaced from onsite thermal production.

Equation 1: Avoided Emissions From Displaced Thermal Energy Production

$$C_T = (CHP_T/\eta_T) * EF_F * (1 \text{ x } 10\text{-}^6)$$

where:

C_T = CO_2 Emissions From Displaced Onsite Thermal Production (lb CO_2)

CHP_T / η_T = CHP System Thermal Output (BTU) ÷ Estimated Efficiency of the Thermal Equipment = Thermal Fuel Savings (BTU)

EF_F = Fuel-Specific CO_2 Emissions Factor (lb CO_2 / MMBTU)

1 x 10-^{6} = Conversion Factor From BTU to MMBTU

72 Breger, D. (2013, March 5). *Alternative Portfolio Standard and the Energy Efficiency Rebates.* Presentation at the NGA Policy Academy, Philadelphia, PA. Massachusetts Department of Energy Resources. Available at: http://www.nga.org/files/live/sites/NGA/files/pdf/2013/1303PolicyAcademyBREGER.pdf

73 Massachusetts Department of Energy Resources. (2014, August). *Interconnection Project Review Paths (With Recent Changes to Resulting From DPU Order 1-75-E).* Available at: https://sites.google.com/site/massdgic/home/interconnection/interconnection-project-review-paths. See also: DSIRE. (2014, August). *Massachusetts Interconnection Standards.* Available at: http://programs.dsireusa.org/system/program/detail/2774

74 Massachusetts Department of Energy Resources. (2014, August). *Distributed Generation and Interconnection in Massachusetts.* Available at: https://sites.google.com/site/massdgic/home/interconnection

75 Supra footnote 15.

76 US EPA CHP Partnership. (2012, August). *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems.* Available at: http://www.epa.gov/chp/documents/fuel_and_co2_savings.pdf

The second step is to calculate emissions of displaced grid electricity.

Equation 2: Avoided Emissions From Displaced Grid Electricity

$$C_G = [CHP_E / (1 - L_{T\&D})] * EF_G$$

where:

C_G	=	CO_2 Emissions From Displaced Grid Electricity (lb CO_2)
CHP_E	=	CHP System Electricity Output (kWh)
$L_{T\&D}$	=	Transmission and Distribution Losses (Percentage in Decimal Form)
$CHP_E / (1 - L_{T\&D})$	=	Displaced Grid Electricity From CHP (kWh)
EF_G	=	Grid Electricity Emissions Factor (lb CO_2 / kWh)

In the final step, CO_2 emissions from the CHP plant are deducted from the sum of Equations 1 and 2.

Fuel-specific CO_2 emissions factors — that is, EF_F in Equation 1 — are typically derived from the inherent energy density of a particular fuel. Table 3-2 lists default emissions factors for select fuels typically used in separate thermal production.

Table 3-2

Default CO_2 Emissions Factors for Fuels Typically Displaced by CHP (HHV)[77]

Fuel Type	CO_2 Emissions Factor (lb/MMBTU)
Natural Gas	116.9
Distillate Fuel Oil #2	163.1
Residual Fuel Oil #6	165.6
Coal Anthracite	228.3
Coal Bituminous	205.9
Coal Sub-bituminous	213.9
Coal Lignite	212.5
Coal (Mixed Industrial)	207.1

As for displaced grid emissions factors — that is, EF_G in Equation 2 — there are several methods used to estimate this value. Most accurate among them is to use a dispatch model. Dispatch modeling demonstrates how generation dispatch for a given region and resource mix would respond to a reduction in demand resulting from the addition of specific CHP resources. The change in emissions is then calculated for that change in dispatch. However, dispatch models are complicated and costly to run. Consequently, the EPA offers a very simple alternative derived from historic performance characteristics of regional electric systems, as reported in the eGRID.[78]

The EPA's eGRID provides two aggregation measures: one based on the average emissions of non-baseload generators and a second based on the average emissions of all fossil fuel generators. Both measures recognize that certain clean energy technologies like CHP are more likely to substitute for existing and/or new fossil generation and not generation from existing "must run" resources, such as nuclear, hydro, and renewables. For baseload CHP systems with high annual capacity factors (i.e., >6500 operating hours), EPA analysis suggests that the average emissions factor of fossil fuel plants provides a reasonable estimate. For CHP operating less than 6500 hours per year, the system can be assumed to displace marginal generating units. In this case, the EPA has recommended using the average emissions factor for non-baseload generation. Average CO_2 emissions rates of fossil fuel generation are generally greater than those of non-baseload generation,[79] but vary from being 35 percent greater (for the Western Electricity Coordinating Council) to 10 percent less (in the case of Nonprofit Coordinating Committee NYC/Westchester) than non-baseload rates across subregions. The EPA has developed an online tool, the CHP Emissions Calculator, which uses the series of equations shown previously with eGRID subregional emissions rates to estimate reductions in CO_2, NO_X, SO_2, methane, and nitrous oxide.[80]

Because the eGRID geographic averages do compromise accuracy for simplicity, this approach (like the thermal credit discussed earlier) has been a point of contention.

77 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Table C-1 of Subpart C. Available at: http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=f483e9df938aea70b74776fc6a440d02&ty=HTML&h=L&r=PART&n=pt40.21.98#ap40.21.98_138.1

78 US EPA, eGRID. (2012). *Summary Tables for Subregions.* Available at: http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf

79 Supra footnote 76.

80 US EPA. (2014, July 30). *CHP Emissions Calculator.* Available at: http://www.epa.gov/chp/basic/calculator.html

To help address concerns and facilitate state air quality and energy planners in developing clean power plans, the EPA recently released a new online tool, AVoided Emission and geneRation Tool (AVERT). AVERT quantifies the CO_2, NO_X, and SO_2 emissions benefits of energy efficiency and renewable energy policies and programs based on temporal energy savings and hourly generation profiles using a marginal emissions rate method.[81] AVERT generally falls between dispatch models and eGRID emissions factors in terms of both simplicity and accuracy.

5. Co-Benefits

CHP systems outside of the electric power sector can deliver an unusually wide range of benefits, not just for the host facilities but also for society and the utility system.

For industrial and commercial enterprises, a primary motivation for investing in CHP systems is to meet electricity and thermal energy demands at lower cost. In this way, CHP is set apart from other GHG compliance options in that it directly improves a business' competitiveness. CHP upgrades can improve operations and energy supply reliability, mitigating the risk of grid outages to the firm. By saving energy, CHP reduces all air and solid pollution associated with the substituted fuel consumption, including criteria pollutant and toxic emissions — and therefore can lead to lower compliance costs for other environmental regulations. The methods for quantifying those reductions are essentially the same as the methods used to calculate GHG reductions, with the avoided emissions approach offering a more accurate picture of the impacts.

As to system benefits, CHP installations represent low-cost generation capacity additions, which can be dispatched as firm capacity. If appropriately scaled and strategically targeted within certain locations, CHP can relieve congestion on the grid, effectively delaying costly expansions and upgrades, which can translate into lower utility rates. By consuming energy onsite, CHP avoids transmission and distribution line losses. CHP can also conserve water resources when compared to the 0.2 to 0.6 gallons of water consumed per kWh in a typical coal-fired power plant.[82] With opportunities at manufacturing, commercial, and institutional facilities in every state, CHP development can stimulate the creation of technically demanding and highly skilled jobs[83]

The full range of potential co-benefits for society and the utility system are summarized in Table 3-3. Benefits that

Table 3-3

Types of Co-Benefits Potentially Associated With CHP in the Commercial, Institutional, and Manufacturing Sectors

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Yes
Other	

81 US EPA. (2014, July 30). *AVERT.* Available at: http://epa.gov/avert/

82 EPRI. (2002). *Water & Sustainability: US Water Consumption for Power Production.* Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001006786

83 The aforementioned 2008 ORNL study found a CHP goal of 20 percent of generation capacity would stimulate $234 billion in capital investment and create nearly one million new jobs by 2030.

accrue to the utility customer who owns a CHP system are additional to those listed.

6. Costs and Cost-Effectiveness

CHP is one of the most cost-effective ways to reduce CO_2 emissions. That CHP is an underutilized opportunity for GHG emissions reductions is a conclusion reinforced by the findings of various studies in recent years.

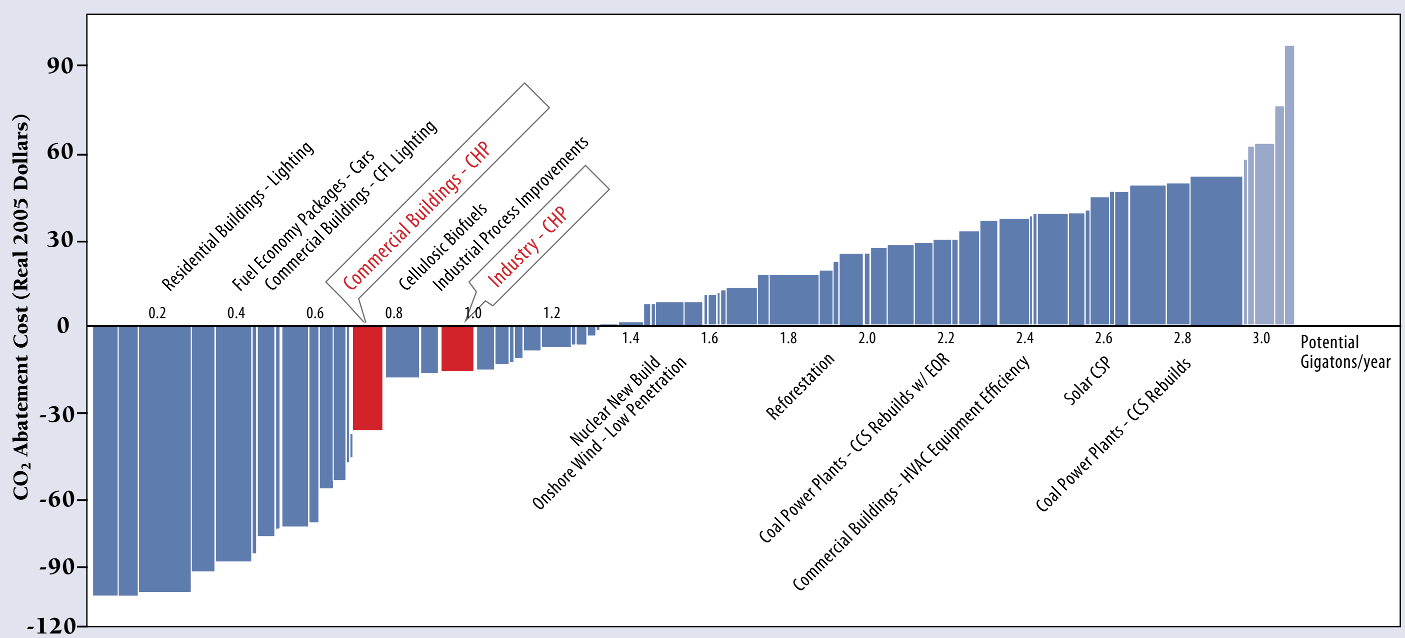
A 2009 report by McKinsey & Company estimated there to be 50 GW of cost-effective CHP in industrial and large commercial/institutional applications through 2020, in which "cost-effective" denotes only investments that had positive net-present values over the lifetime of the measure.[84] These projects were estimated to reduce 100 million metric tons of CO_2 annually (Figure 3-5). Substituting today's natural gas prices and market outlook in the analysis would presumably boost this estimate of economic feasibility.

Mentioned earlier, a 2013 analysis by ICF International found a total of 125 GW of technical potential for CHP at existing industrial (56 GW) and commercial (69 GW) facilities, corresponding to a capacity roughly five times the capacity of the coal-fired generation poised to retire between 2012 and 2016.[86] Technical potential here accounts for sites that have high thermal and electric demands suitable to CHP, but does not consider economic factors relevant to project investment decisions.[87] The states with the greatest technical potential (>5 GW) were California, Florida, Illinois, Michigan, New York, Ohio, Pennsylvania, and Texas.[88] When ICF screened for economic viability by incorporating energy prices (excluding other economic incentives), it found that 42 GW of technical potential had an investment payback period of less than ten years, 6 GW of which would pay for itself through energy savings within five years.[89]

Another more recent study evaluated the impacts of the EPA's proposed GHG regulations on CHP deployment. Using ICF International's CHPower and IPM models, the Center for Clean Air Policy analyzed rates of technology adoption at existing and new facilities across the country in light of the EPA's proposed 111(d) GHG regulations for

Figure 3-5

Comparative Costs of CO_2 Reduction Technologies[85]



84 McKinsey & Company. (2009). *Unlocking Energy Efficiency in the US Economy.* Available at: http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy

85 Supra footnote 15.

86 Supra footnote 14.

87 Also note that the ICF analysis of technical potential does not include EGUs.

88 For summary tables broken down by state, size, and sector, see: supra footnote 14.

89 Ibid.

existing EGUs.[90] Reflecting technical limitations, economic factors, as well as rates of market acceptance, the study determined that a future scenario with 111(d) rules in effect would result in 10 GW of new CHP by 2030, where these 10 GW represent projects that are both economically feasible and "accepted" by firms. The study concludes that 111(d)

Table 3-4

Summary Table of Typical Costs and Performance Characteristics by CHP Technology[91]

Technology	Recip. Engine	Steam Turbine	Gas Turbine	Microturbine	Fuel Cell
Electric efficiency (HHV)	27-41%	5-40+%*	24-36%	22-28%	30-63%
Overall CHP efficiency (HHV)	77-80%	near 80%	66-71%	63-70%	55-80%
Effective electrical efficiency	75-80%	75-77%	50-62%	49-57%	55-80%
Typical capacity (MW)	.005-10	0.5-several hundred MW	0.5-300	0.03-1.0	200-2.8 commercial CHP
Typical power to heat ratio	0.5-1.2	0.07-0.1	0.6-1.1	0.5-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($/kW)	1,500-2,900	$670-1,100	1,200-3,300 (5-40 MW)	2,500-4,300	5,000-6,500
Non-fuel O&M costs ($/kWh)	0.009-0.025	0.006 to 0.01	0.009-0.013	0.009-.013	0.032-0.038
Availability	96-98%	near 100%	93-96%	98-99%	>95%
Hours to overhauls	30,000-60,000	>50,000	25,000-50,000	40,000-80,000	32,000-64,000
Start-up time	10 sec	1 hr -1 day	10 min -1 hr	60 sec	3 hrs -2 days
Fuel pressure (psig)	1-75	n/a	100-500 (compressor)	50-140 (compressor)	0.5-45
Fuels	natural gas, biogas, LPG, sour gas, industrial waste gas, manufactured gas	all	natural gas, synthetic gas, landfill gas, and fuel oils	natural gas, sour gas, liquid fuels	hydrogen, natural gas, propane, methanol
Uses for thermal output	space heating, hot water, cooling, LP steam	process steam, district heating, hot water, chilled water	heat, hot water, LP-HP steam	hot water, chiller, heating	hot water, LP-HP steam
Power Density (kW/m^2)	35-50	>100	20-500	5-70	5-20
NO_X (lb/MMBTU) (not including SCR)	0.013 rich burn 3-way cat. 0.17 lean burn	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.036-0.05	0.015-0.036	0.0025-.0040
NO_X (lb/$MWh_{Total\ Output}$) (not including SCR)	0.06 rich burn 3-way cat. 0.8 lean burn	Gas 0.4-0.8 Wood 0.9-1.4 Coal 1.2-5.0.	0.17 - 0.25	0.08 - 0.20	0.011-0.016

** Power efficiencies at the low end are for small backpressure turbines with boiler and for large supercritical condensing steam turbines for power generation at the high end.*

90 Davis, S., & Simchak, T. (2014, May). *Expanding the Solution Set: How Combined Heat and Power Can Support Compliance With 111(D) Standards for Existing Power Plants.* Center for Clean Air Policy. Available at: http://ccap.org/assets/CCAP-Expanding-the-Solution-Set-How-Combined-Heat-and-Power-Can-Support-Compliance-with-111d-Standards-for-Existing-Power-Plants-May-2014.pdf

91 US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies.* Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf. Note that values are illustrative for commercially available technologies. Installed cost for most CHP technologies consists of costs related to equipment, installation labor and materials, engineering, project management, and financial carrying costs during the construction period. All costs are in 2014$.

rules will not be sufficient to drive development of CHP resources toward the full technical potential, and that the emissions limits must be accompanied by complementary policies to support CHP uptake as a compliance option.

Generalizing about costs on the project level is problematic, given the extent to which site-specific factors determine the configuration requirements and the extent to which the local regulatory environment can add considerably to administrative overhead. According to the National Regulatory Research Institute, whether using payback period, net-present value, upfront capital costs, technical and economic potentials, or other indicators of economic value, each have advantages and disadvantages in communicating the underlying issues influencing technology adoption.[92] There are furthermore multiple points of view from which to evaluate the cost-effectiveness of CHP, whether from that of the participants, the gas utility, the electric utility, the ratepayer, or society generally. Below, three different analyses of cost-effectiveness are summarized on a project basis. For additional analyses, refer to Chapter 2.

Isolating installed costs for new projects, Table 3-4 compares typical applications by technology class (in 2013$). Gas turbines ranging in size from 5 to 40 MW may have costs from $1200/kW to $3300/kW. Steam turbines may range anywhere from $670/kW to $1100/kW. Reciprocating engines have installed costs ranging from $1500/kW to $2900/kW, whereas microturbines in grid-tied CHP installations can cost from $2500/kW to $4300/kW. Lastly, fuel cells are the most costly, with total installed costs ranging from $5000/kW to $6500/kW.

Cost-effectiveness can also be illustrated by comparing cash outlays over the course of the investment lifetime. In

Table 3-5

Financial Comparison of Two Typical Options for Boiler Replacement[93]

	Natural Gas Boilers	Natural Gas CHP	Impact of CHP Increase / (Decrease)
Peak Boiler Capacity, MMBTU/hr input	120	NA	
Peak Steam Capacity, MMBTU/hr	96	96	
Average Steam Production, MMBTU/hr	76.8	76.8	
Boiler Efficiency	80%	NA	
Electric Generating Capacity, MW	NA	14	
CHP Electric Efficiency	NA	31%	
CHP Total Efficiency	NA	74%	
Steam Production, MMBTU/year	614,400	614,400	0
Steam Production, MMlbs/year	558.6	558.6	0
Power Generation, kWh/year	NA	106,400,000	106,400,000
Fuel Use, MMBTU/year	768,000	1,317,786	549,786
Annual Fuel Cost	$4,608,000	$7,906,716	$3,298,719
Annual O&M Cost	$729,600	$1,687,200	$957,600
Annual Electric Savings	0	($6,703,200)	($6,703,200)
Net Annual Operating Costs	$5,337,600	$2,890,719	($2,447,331)
Net Steam Costs, $/1000lbs	$9.56	$5.18	($4.38)
Capital Costs	$4,200,000	$21,000,000	$16,800,000
10 Year Net Cash Outlays	$65,389,602	$54,138,850	($11,250,752)
Payback – CHP vs. Gas Boilers			6.9 years
10 Year IRR - CHP vs. Gas Boilers			10%
10 Year NPV – CHP vs. Gas Boilers			$2,580,588

Source: ICF International

Notes: Based on 8,000 hours facility operation, 7 cents per kWh electricity price, and $6/MMBTU natural gas price. Natural gas boiler estimated capital cost of $35/MBTU/hour input and O&M cost of $0.95/MMBTU input were provided by Worley Parsons. CHP capital cost of $1,500/kW, turbine/generator and heat recovery steam generator O&M costs of $0.009/kWh and 31 percent electrical efficiency are taken from a California Energy Commission Report, “Combined Heat and Power: Policy Analysis and 2011 – 2030 Market Assessment,” 2012. Annual CHP O&M cost includes an amount to maintain the steam system, which is approximated by the O&M cost of the boilers, which produce the same steam output. CHP availability of 95 percent and portion of electric price avoided by on-site generation of 90 percent are values based on typical CHP feasibility analyses. 10 year net cash outlays are the sum of 10 year's operating costs escalated at 3 percent annually. NPV determined using a 7% discount rate. All efficiency values and natural gas prices are expressed as higher heating values.

92 Costello, K. (2014, June). *Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do?*Report No. 14-06. National Regulatory Research Institute. Available at: http://www.nrri.org/documents/317330/16dd1f89-c8ec-44db-af73-7c6473a3ef09

93 US EPA CHP Partnership. (2013, March 11). *Fact Sheet: CHP as a Boiler Replacement Opportunity.* Available at: http://www.epa.gov/chp/documents/boiler_opportunity.pdf

the context of Boiler MACT compliance, a common choice for facilities seeking to replace a coal-fired or other boiler system is a natural gas boiler. The financial analysis shown in Table 3-5 was developed by ICF International for the EPA's CHP Partnership program. It juxtaposes two options for meeting the average steam demand of a small industrial or medium-sized institutional facility.[94] The first consists of two natural gas boilers, and the second is a CHP system based on a natural gas combustion turbine and a heat recovery steam generator. As the financial comparison details, the CHP system requires an upfront capital expenditure of $16.8 million more than the gas boilers, but produces net annual operating savings of $2.4 million, which yields a payback period of less than seven years, and over ten years generates an internal rate of return of ten percent and a net present value of approximately $2.6 million.

Yet another way to characterize the cost-effectiveness of a CHP project is to compare performance across other generation classes of similar capacity size. Table 3-6 does this, listing annual electric output, thermal output, and avoided emissions from a typical 10-MW gas turbine CHP system, alongside a 10-MW apportionment of utility-scale wind, photovoltaic, and natural gas combined-cycle generators. On a capacity basis, the 10 MW of CHP displaces more CO_2 emissions than any of the other options. Homing in on a comparison with wind power, the CHP project achieves 60 percent more CO_2 savings than the wind project, while generating 2.5 times the electric output, at 83 percent of the capital cost.

In utility regulation, standard tests for cost-effectiveness are used to evaluate energy efficiency programs,[96] and can also be useful for determining the relative value of CHP programs. Cost-effectiveness can be assessed from many different perspectives, whether from that of the gas utility,

Table 3-6

CHP Energy and CO_2 Emissions Savings Potential Compared to Other Generation Options[95]

Category	10 MW CHP	10 MW PV	10 MW Wind	10 MW Natural Gas Combined-Cycle
Annual Capacity Factor	85%	25%	34%	70%
Annual Electricity	74,446 MWh	21,900 MWh	29,784 MWh	61,320 MWh
Annual Useful Heat Provided	103,417 MWh	None	None	None
Footprint Required	6,000 sq ft	1,740,000 sq ft	76,000 sq ft	N/A
Capital Cost	$20 million	$48 million	$24 million	$9.8 million
Annual National Energy Savings	343,787 MMBTU	225,640 MMBTU	306,871 MMBTU	163,724 MMBTU
Annual National CO_2 Savings	44,114 Tons	20,254 Tons	27,546 Tons	28,233 Tons
Annual National NO_X Savings	86.9 Tons	26.8 Tons	36.4 Tons	76.9 Tons

The values in Table 3-6 are based on:

- 10 MW Gas Turbine CHP - 28% electric efficiency, 68% total CHP efficiency, 15 ppm NOx emissions
- Capacity factors and capital costs for PV and Wind based on utility systems in DOE's Advanced Energy Outlook 2011 Capacity factor, capital cost and efficiency for natural gas combined-cycle system based on Advanced Energy Outlook 2011 (540 MW system proportioned to 10 MW of output), NGCC NO_X emissions 9 ppm
- CHP, PV, Wind and NGCC electricity displaces National All Fossil Average Generation resources (eGRID 2010) - 9,720 BTU/kWh, 1,745 lbs CO_2/MWh, 2.3078 lbs NO_X/MWh, 6% T&D losses; CHP thermal output displaces 80% efficient on-site natural gas boiler with 0.1 lb/MMBTU NO_X emissions
- CHP, PV, Wind and NGCC electricity displaces EPA eGRID 2010 California All Fossil Average Generation resources - 8.050 BTU/kWh, 1,076 lbs CO_2/MWh, 0.8724 lbs NO_X/MWh, 6% T&D losses; CHP thermal output displaces 80% efficient on-site natural gas boiler with 0.1 lb/MMBTU NO_X emissions

94 Supra footnote 93.

95 Supra footnote 14.

96 National Action Plan for Energy Efficiency. (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policymakers.* Energy and Environmental Economics, Inc. and The Regulatory Assistance Project. Available at: www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

the electric utility, ratepayers, or the participating entities. Tests like the Program Administrator Cost test, the Total Resource Cost test, and the Rate Impact Measure tests can help account for how costs and benefits affect all parties involved. Appendix A of the 2013 SEE Action report describes how these tests can be used to evaluate benefits and costs as they accrue across parties and energy types.[97]

7. Other Considerations

Increased deployment of CHP outside of the electric sector will have impacts both on natural gas utilities and electric utilities. Each is discussed briefly below.

Natural Gas Distribution Utilities

CHP in commercial and institutional sectors, where ICF International estimates that more than half of untapped technical potential is located (69 of 125 GW), may offer a substantial new market opportunity for natural gas local distribution companies.[98] Gas utilities can bring their technological expertise to bear, working with customers to develop energy efficiency solutions that ensure customer retention. A gas utility can also potentially provide financial support for capital upgrades over longer-term investment horizons, consistent with its business model.

A case study from Philadelphia Gas Works (PGW) exemplifies a partnership of this nature. PGW collaborated with the Four Seasons hotel in downtown Philadelphia to develop a technology configuration that would deliver reasonable savings, including introducing the customer to the microturbine technology it would ultimately select. The project was based around three 65-kW gas microturbines to provide 100 percent of the hotel's domestic hot water, 25 percent of its electric, and 15 percent of its heating needs. To address upfront costs, PGW developed an arrangement whereby it provided $1.2 million in upfront capital, to be paid back through a surcharge on the hotel's energy bills. Recovery of PGW's cost was estimated to take three years, after which the customer would financially benefit from the energy savings over the lifetime of the investment.[99]

Oregon is one state adopting specific provisions to enable natural gas utility ownership and investment in CHP. Oregon Senate Bill 844 of 2013 created an inventive program for gas utilities that would allow recovery of investments in GHG reduction projects.[100] As of August 1, 2014, the rules were still being finalized by the Public Utility Commission, but gas utilities had identified CHP as a primary area of interest.[101] Baltimore Gas and Electric and New Jersey Natural Gas also provide financial support and incentives to industrial and commercial customers who install CHP. Baltimore Gas and Electric funds this through a ratepayer-funded energy efficiency program, and New Jersey Natural Gas through loan repayment schemes negotiated between the utility and the participant. A 2013 report from the American Council for an Energy-Efficient Economy (ACEEE) provides an extensive discussion of the role for natural gas utilities in developing CHP more fully.[102]

Electric Utilities

Distributed generation, including CHP, is causing a transformation in the way electricity is generated, delivered, and paid for in the United States, and how it fits within existing regulatory frameworks. The shift away from centralized production toward dispersed, demand-side resource solutions signifies a reduction in utility revenue and has been perceived as chief among threats to the traditional utility business model. This stance is beginning to evolve, however, as utilities engage stakeholders and look for ways to position themselves in this new order.[103,104] Perhaps especially with regard to CHP, where energy falls outside the

97 Supra footnote 22.

98 Larger industrial facilities, in contrast, are usually connected to interstate gas pipelines or consume other fuels. CHP applications smaller than 100 MW would usually be connected to a distribution network.

99 Supra footnote 22.

100 Oregon State Legislature, Senate Bill 844. Available at: https://olis.leg.state.or.us/liz/2013R1/Measures/Text/SB844/Enrolled

101 Oregon Public Utility Commission, Docket No. AR 580. Available at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=18862

102 Chittum, A., & Farley, K. (2013, July). *How Natural Gas Utilities Can Find Value in CHP.* ACEEE. Available at: http://www.aceee.org/files/pdf/white-paper/chp-and-gas-utilities.pdf

103 Kind, P. (2013, January). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.* Edison Electric Institute. Available at: http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

104 ICF International. (2014). *From Threat to Asset: How CHP Can Benefit Utilities.* Available at: http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities

core business of most participating enterprises, utilities are uniquely positioned to shoulder risk and responsibility and provide assistance in design, installation, and operations to maximize benefits to the electrical system. Examples of how electric utilities can profit from distributed CHP development are discussed in Chapter 2. Creating avenues for utility participation in CHP development is expected to be a growing focus for regulators seeking to address the administrative, financial, and technical barriers that have led to persistently low rates of adoption. Both the 2013 SEE Action study and a 2013 ACEEE report highlight possible considerations for utility participation in CHP markets.[105]

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CHP in the commercial, institutional, and manufacturing sectors.

- ACEEE. *Technical Assistance Toolkit, Policies and Resources for CHP Deployment*. Available at: http://energytaxincentives.orgwww.energytaxincentives.org/policies-and-resources-chp-deployment
- ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States*. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx
- NASEO. (2013). *Combined Heat and Power: A Resource Guide for State Energy Officials*. Available at: http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf
- The Regulatory Assistance Project. (2014, February). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States*. Available at: http://www.raponline.org/press-release/standby-rates-for-combined-heat-and-power-need-a-fresh
- The Regulatory Assistance Project. (2003). *Output Based Emissions Standards for Distributed Generation*. Available at: http://www.raponline.org/docs/RAP_IssuesLetter-OutputBasedEmissions_2003_07.pdf
- US DOE, US EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies*. Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
- US DOE. *Boiler MACT Technical Assistance Program* website. Available at: http://energy.gov/eere/amo/boiler-mact-technical-assistance-program
- US DOE. *CHP Technical Assistance Partnerships* website. Available at: http://www1.eere.energy.gov/manufacturing/distributedenergy/chptaps.html
- US DOE & ORNL. (2012). *Guidance for Calculating Emission Credits Resulting From Implementation of Energy Conservation Measures*. Available at: http://info.ornl.gov/sites/publications/Files/Pub37258.pdf
- US DOE & ORNL. (2008, December). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future*. Available at: https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_report_12-08.pdf
- US EPA. (2014, August). *Output-Based Regulations: A Handbook for Air Regulators*. Available at: http://www.epa.gov/chp/documents/obr_handbook.pdf
- US EPA CHP Partnership website. Available at: http://www.epa.gov/chp/
- US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies*. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

9. Summary

CHP offers a technologically mature, cost-effective, and near-term strategy for reducing GHG emissions, with technical potential distributed across the industrial, commercial, and institutional sectors. Grid-tied CHP facilities, however, can be complex, site-specific installations that carry significant technical and administrative burdens that have led to low rates of adoption, even in jurisdictions where financial incentives improve economic feasibility. Designing CHP to maximize co-benefits to the system, such as grid reliability, critical infrastructure resilience, and reduced congestion, further requires careful consideration and expertise that is typically beyond the field of participating enterprises. Concerted effort through supporting policy and regulation, as well as utility cooperation, will be required to take full advantage of CHP as a GHG reduction compliance option.

105 US DOE, US EPA, & SEE Action Network. Available at https://www4.eere.energy.gov/seeaction/; US EPA, CHP Partnership. Available at: http://www.epa.gov/chp/; Chittum, A. (2013, July). *How Electric Utilities Can Find Value in CHP.* ACEEE. Available at: http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf

4. Improve Coal Quality[1]

1. Profile

Power plant boilers are designed to accommodate a range of types of coal but, within this range, variations in coal properties can affect performance and efficiency. A boiler designed to burn a high rank bituminous coal is going to perform quite differently if lower rank sub-bituminous coal is introduced, and properties such as high ash or sulfur content can impair not only the thermal performance of the boiler, but also associated duct work and virtually all boiler auxiliary systems, including sootblowing, forced and induced draft systems, steam temperature control, bottom and fly ash removal, pulverizers, and primary air, secondary air, burners, and combustion controls.[2] Air permit conditions for new or modified boilers specify fuel type and quality, and require fuel sampling in order to bind the range of potential emissions that are associated with variations in these parameters. Off-design fuels can affect boiler performance and efficiency.

Higher ash content in coal affects every piece of plant equipment that handles and processes coal, such as conveyors, pulverizers, crushers, storage, and so forth. The increased load on this equipment also increases auxiliary power consumption; that is, the quantity of plant-site energy needed simply to operate the plant, which reduces the quantity of electricity that can be transmitted for sale, thus increasing the plant's operating costs and decreasing its profit potential.

Plant operators understand that there are benefits from specifying coal quality in purchasing contracts, even if higher quality coal is more expensive. Even before the establishment of environmental requirements for coal quality, operators of coal-fired power plants voluntarily established standards and specifications for the fuel they purchased so they would be able to effectively operate their boilers and minimize the amount of time the boilers had to be taken off-line for maintenance. Boilers are typically designed and constructed based on a specification coal or range of specification coals that the purchaser intends to use as its fuel, such as that secured for a long-term purchase agreement with a given mine or group of mines. Once a boiler is constructed and in operation, owner/operators will typically continue to specify fuel coals to be compatible with the design characteristics of their boiler and boiler auxiliaries and any associated regulatory requirements. Alternatively, the owners/operators may make the decision to purchase off-spec fuels that they can live with to provide an economic advantage, assuming there are no regulatory requirements that influence those decisions.

Some coal processing may be required for an as-mined coal to meet the specifications of purchasers.[3] To maintain coal quality within specified ranges and meet boiler performance objectives, coals with different properties can be blended, either by the coal producer or at a power plant. Another option for meeting coal quality specifications is through "beneficiation." Coal beneficiation is the industry's term for any of several processes and treatments that improve coal quality. The most common of these beneficiation processes is "coal washing."

1 Adapted from James, C., & Gerhard, J. (2013, February). *International Best Practices Regarding Coal Quality.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6438

2 The trend toward increased use of Powder River Basin coals, even in the Eastern United States, has led to newer boilers being designed to operate within broader ranges of fuel types and quality. Tangentially fired boilers can also accommodate a broader range of fuel types and quality. See, for example, the Alstom boiler specification sheet available at: http://www.alstom.com/Global/Power/Resources/Documents/Brochures/pulverised-coal-boiler-tower-type-boilers.pdf.

3 The Virginia Center for Coal and Energy Research. (2009). *Meeting Projected Coal Production Demands in the USA: Upstream Issues, Challenges, and Strategies.* Prepared for the National Commission on Energy Policy. Chapter 4 (Coal Preparation). Available at: http://www.energy.vt.edu/ncepstudy/outline/Coal_Production_Demands_Chapter4.pdf.

Beneficiation results in a variety of improvements to power plant operations that directly affect the profitability of a coal plant, its emissions and ability to meet environmental requirements, and its ability to avoid future economic risks. In particular, coal washing can dramatically reduce the sulfur and ash content of coal, resulting in a significant reduction in air emissions, a reduction in auxiliary power demand, and a number of other co-benefits.

2. Regulatory Backdrop

Coal quality standards are typically implemented through state or local construction and operating permits and via language in procurement contracts.

There are several ways in which quality control requirements can be specified in a permit. For example, the source's operating permit may specify a maximum ash content and a maximum sulfur content for coal burned in a boiler. These conditions are typically enforced through sampling, recordkeeping, and reporting requirements.

Although air permit limitations are important for regulatory purposes, contractual arrangements between the seller of the coal and the purchaser are the primary means by which commercial quality control is established. One example of contractual standards for coal quality comes from the New York Mercantile Exchange. Under standard New York Mercantile Exchange rules, there are a number of coal quality specifications; for example, the following are specifications for Central Appalachian Coal:

Coal delivered under this contract shall meet the following quality specifications on an as-received basis [as-received does not refer to subsections (6) and (7)]:

1. **BTU**[4]: Minimum 12,000 BTU/lb, gross calorific value, with an analysis tolerance of 250 btu/lb below (A.S.T.M. D1989)
2. **Ash**: Maximum 13.50%, with no analysis tolerance (A.S.T.M. D3174 or D5142) (3) Sulfur: Maximum 1.00%, with an analysis tolerance of 0.050% above (A.S.T.M. D4239)
3. **Moisture**: Maximum 10.00%, with no analysis tolerance (A.S.T.M. D3302 or D5142)
4. **Volatile Matter**: Minimum 30.00%, with no analysis tolerance (A.S.T.M. D5142 or D3175)
5. **Grindability**: Minimum 41 Hardgrove Index (HGI) with three-point analysis tolerance below (A.S.T.M. D409)
6. **Sizing**: "Three inches topsize, nominal, with maximum fifty five per cent passing one quarter inch square wire cloth sieve to be determined basis the primary cutter of the mechanical sampling system (A.S.T.M. D4749)[5]" [*sic*]

Under these kinds of contractual arrangements, quality standards are enforced by the parties to the contract, with recourse to the appropriate judicial body in cases of disputes over performance.[6]

3. State and Local Implementation Experiences

Coal specifications were utilized for the design of water tube boilers in the mid to late 1800s and were in place for some of the early steam electric stations that were in operation prior to 1900. More than a hundred years ago, the United States government adopted coal quality specifications for the coal it purchases.[7] In the years since, quality specifications have become an industry norm and essentially all purchasers of coal, including those who use it to generate electricity, have experience with such specifications.

Coal beneficiation has been a common practice for meeting coal quality specifications across the United States. However, coal beneficiation is most economical and beneficial today when applied to fuel that will be burned in a pulverized boiler. Less coal washing occurs in the United States today than in the 1980s and 1990s owing to:

- increased use of fluidized bed boilers;
- increased availability of coal from the Powder River Basin; Powder River Basin coal has a relatively low ash content of five to six percent, is also lower in sulfur than Appalachian coal, and is mined almost exclusively through longwall or opentop extraction,

4 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit.

5 CME Group. (2012). NYMEX Rulebook: Chapter 260 – *Central Appalachian Coal Futures.* Available at: http://www.cmegroup.com/rulebook/NYMEX/2/260.pdf.

6 Contracts generally specify the method of resolving conflicts, as well as the adjudicatory body and jurisdiction.

7 Pope, G. (1910). *Purchase of Coal by the Government under Specifications: with Analyses for Coal Delivered in the Fiscal Year 1908-09.* Government Printing Office. Available at: http://pubs.usgs.gov/bul/0428/report.pdf.

which optimizes the amount of coal that can be removed per unit of labor;

- increased coal prices – boilers (including pulverized coal boilers) were designed and/or modified with more flexibility to operate acceptably with the lower quality, less expensive coals; and
- utilization of new or improved emissions controls that allowed the use of lower quality/lower cost coals while still meeting air emissions requirements.

Thus, it is often possible for coal quality specifications to be met without requiring any coal beneficiation techniques.

Air pollution regulators in virtually all states will be familiar with the practice of limiting the sulfur and ash content of coal in power plant operating permits. This, too, has become an industry norm. But because they generally don't specify *how* sources will meet those limitations, air regulators in some cases may not be familiar with the costs or benefits of coal beneficiation.

4. Greenhouse Gas Emissions Reductions

Historically, the primary reasons for improving coal quality have been to increase the thermal efficiency of coal-fired power plants and to improve overall profit margins. Although air pollution concerns have not been the primary driver, a significant body of research indicates that beneficiation can result in substantial direct and indirect emissions reductions.

By improving thermal efficiency (heat rate), coal washing can directly reduce the carbon dioxide (CO_2) emissions rate of coal-fired boilers. Waymel and Hatt assessed the costs and benefits of improving coal quality for a hypothetical 500-megawatt (MW) coal plant, with a heat rate of 10,000 BTU per kilowatt hour (kWh), burning bituminous coal. Their results indicate that a heat rate improvement to 9890 BTU/kWh, that is, a one-percent increase in boiler efficiency, can be achieved through coal washing.[8] Each one-percent increase in boiler thermal efficiency can in turn decrease CO_2 emissions by two to three percent.[9] These results will vary depending on the specific fuel combusted; plants burning lower quality coals are likely to have more potential to improve thermal efficiency.[10] The Asian Development Bank (ADB) conducted an extensive survey of the Indian coal industry in the 1990s and found that for each 10-percent reduction in ash content, thermal efficiency can be improved by up to six percent, with an average of one to two percent; CO_2 emissions were found to decrease by 2.5 to 2.7 percent on average.[11] The ADB study included coals with high ash content, more representative of US lignite coals, and higher than the typical bituminous and sub-bituminous coals more commonly used in the United States.

In addition to boiler heat rate improvements, coal washing can also reduce auxiliary power demand (i.e., the electricity consumed onsite to power auxiliary equipment such as coal and ash handling equipment, fans, pollution control equipment, and the like). Reducing auxiliary power demand reduces the net emissions rate (pounds of emissions per net megawatt hour (MWh) delivered to the grid) of a power plant. The previously cited ADB survey noted a range of 8 to 12 percent of the gross power output at coal-fired power plants was used for plant auxiliary power requirements and found that auxiliary power demand declined by 10 percent on average with coal washing.[12]

Finally, as coal beneficiation can reduce the weight of raw coal by up to 25 percent, a net reduction in transportation energy demand of about 20 percent is

8 Waymel, E., & Hatt, R. (1987). *Improving Coal Quality: An Impact on Plant Performance.* Lexington, KY: Island Creek Corporation. (Estimated publication date based on references in the paper.) Available at: http://www.coalcombustion.com/PDF%20Files/Improving%20Coal%20Quality.pdf.

9 Supra footnote 3.

10 The U.S Environmental Protection Agency's (EPA) Technical Support Document (TSD) for 111(d): *GHG Abatement Measures,* describes several techniques to improve boiler efficiency. These techniques are also covered in Chapter 1 of this document (Optimize Plant Operations). The EPA's technical analysis does not quantify the CO_2 emissions impact of each specific technique for improving heat rates, as boiler types and fuels combusted in them vary. Rather, the IPM modeling conducted for the EPA and described in Section 2.6.4 of the EPA's TSD analyzed the combined influence from all heat rate improvement technologies on CO_2 emissions. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

11 ADB. (1998). *India: Implementation of Clean Technology through Coal Beneficiation.* Project number 26095, prepared for the ADB by Montan-Consulting GMBH in association with International Economic and Energy Consultants and CMPDI International Consultants, India. Available at: http://www2.adb.org/documents/reports/Consultant/IND/26095/26095-ind-tacr.pdf.

12 Ibid.

possible, requiring less fuel to transport the coal from a mine to a power plant, and yielding additional reductions in greenhouse gas (GHG) emissions.

5. Co-Benefits

Several qualitative and authoritative studies discuss factors that affect the performance of coal boilers, and the direction of the particular effect (i.e., increasing or decreasing). The Electric Power Research Institute (EPRI) and many utilities have developed proprietary models that can assess how a variable, or variables, will influence a particular plant.[13] These models require interested users to purchase them to determine specifics. However, agencies have conducted more general and broader studies that can be used to assess why coal quality matters, and what variables are the most important to consider. Evaluating the benefits of improving coal quality also required a search of the early literature, as later studies have been both narrower and more in-depth (looking at a particular variable like ash on a particular type of boiler, like a fluidized bed), and often refer back to the 1980s (and earlier) work as references.

The International Energy Agency (IEA) surveyed coal boiler operators in the early 1990s to assess what variables affect boiler performance and efficiency, and the direction of each variable (beneficial or harmful).[14] Sixty power plants in 12 countries were included in the survey. Based on the survey responses, the IEA concluded that coal quality factors account for up to 60 percent of forced outages at power plants. Applying mineral additives containing aluminum can reduce ash fouling and slagging in pulverized coal boilers by up to 78 percent.[15] Wet pretreatment can reduce the amount of ash that adheres to boiler tubes, thus reducing fouling. Dry additives, such as alumina, can make the ash less sticky and thus reduce the amount of ash that forms on boiler surfaces. Reducing the ash content of coal also makes the coal less abrasive and operators can reduce the amount of scheduled and unscheduled maintenance required to remove the ash accumulation. Reducing the abrasiveness of the ash and sulfur deposits on plant duct work can reduce corrosion that shortens the plant's expected life. The greatest improvements in boiler efficiency and coal quality occurred when the base coal itself was of poor quality, such as lignite coals combusted in the United States and Eastern Europe, and high ash content coals combusted in China and India. In the United States, higher quality bituminous and sub-bituminous coals are more commonly used. And consistent with the Chapter 1 discussion on heat rate improvements, the actual benefits from improved coal quality will vary according to the power plant and its specific operating conditions.

Beneficiation also has benefits for the operation of emissions control devices. About 80 percent of the ash in coal eventually travels through the combustion process and, along with the flue gas, is captured by the emissions control equipment. Coal washing reduces the amount of ash produced and collected by particulate control devices, thereby extending the life of the particulate control devices. Washing or processing coal before it is combusted can also permit the power plant to design and purchase smaller emissions control devices, thus reducing capital costs.

Studies of US coals show that washing reduces sulfur content by 10 to 20 percent (on a lb/MMBTU[16] basis). Ash reductions of 30 to 50 percent were reported for Mexican coals, with a 20- to 30-percent reduction in sulfur content. A National Academy of Sciences study reports sulfur reductions for China's coals of up to 20 percent.[17] A minimum ten-percent reduction in sulfur dioxide (SO_2) is considered to be a conservative assumption of the emissions-savings potential from coal washing. This minimum ten-percent reduction in SO_2 for a 600-MW plant, operating at an 80-percent capacity factor (or 7000 hours per year), would result in a minimum SO_2 annual reduction of 1682 metric tons.

13 Examples include EPRI's Coal Quality Impact Model, EBASCO performance models, heat rate models, or least-cost fuel models.

14 Skorupska, N. (1992). Coal Specifications - *Impact on Plant Performance: An International Perspective.* Presented at Effects of Coal Quality on Power Plants, Third International Conference, EPRI.

15 Vutharulu, H. (1999). Remediation of Ash Problems in Pulverized Coal-fired Boilers. *Fuel.* 78 (15), 1789–1803.

16 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

17 National Research Council. (2004). *Urbanization, Energy and Air Pollution in China: The Challenges Ahead - Proceedings of a Symposium.* Washington, D.C.: National Academies Press.

As noted above, the Waymel and Hatt study assessed the co-benefits of improving coal quality for a hypothetical 500-MW coal plant, with a heat rate of 10,000 BTU per kWh, burning bituminous coal. In addition to the heat rate improvements noted above, they noted a 45-percent decrease in ash and more than a 50-percent decrease in sulfur. The sulfur emissions rate was estimated to decrease from 4.2 lb/MMBTU to 1.9 lb/MMBTU.[18]

The ADB survey cited above mentions several other environmental co-benefits of coal washing. To begin with, the efficiency of electrostatic precipitators improves from 98 to 99 percent.[19] Land requirements for ash disposal are also reduced. For a 1000-MW coal plant, assuming a plant life of 20 years, the amount of land required for ash disposal is reduced from 400 hectares to 229 hectares. Finally, the amount of water required to move ash from the plant to a land disposal site is reduced by 30 percent. For a typical 1000-MW plant, this translates to 11.99 million m^3 per year consumption, compared to 17.05 million m^3 per year for a plant using unbeneficiated coal.

It is also worth repeating that as coal beneficiation can reduce the weight of raw coal by up to 25 percent, less energy is needed for transportation of the fuel, and additional reductions in fine particulates, nitrogen oxides, and other pollutants can result.[20] In a 2003 study of Chinese coals, Glomrod and Taoyuan calculated that coal cleaning removes 25 percent of the coal weight, resulting in a 20-percent net reduction in transportation demand for each unit of thermal energy.[21]

The full range of co-benefits that can be realized through coal beneficiation are summarized in Table 4-1.

18 Waymel & Hatt, supra footnote 8.

19 In effect, this is a 50-percent improvement in the particulate collection efficiency. A 98-percent efficiency means that, for each 100 tons of particulate mass in the flue gas, two tons would not be captured and would be emitted to the atmosphere. A 99-percent efficiency means that for each 100 tons of particulate mass in the flue gas, one ton would not be captured.

20 Supra footnote 11. Data on transport savings were calculated for India at Table 4-2 on page 69 of this document.

21 Glomrod, S., & Taoyuan, W. (2003). *Coal Cleaning: A Viable Strategy for Reduced Carbon Emissions and Improved Environment in China?* Norway and China. Available at: http://www.ssb.no/a/publikasjoner/pdf/DP/dp356.pdf.

Table 4-1

Types of Co-Benefits Potentially Associated With Coal Beneficiation

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_x[22]	Yes
SO_2	Yes
PM[23]	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes[24]
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	No
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Maybe
Other	

22 Nitrogen oxides.

23 Particulate matter.

24 Depending on the coal beneficiation techniques used, water consumption can be a potential concern. Improved thermal efficiency reduces water consumption per MWh of generating output, which must be weighed against any water impacts of the techniques that are used to improve coal quality.

6. Costs and Cost-Effectiveness

Power plant owners benefit directly from burning better quality coal. Coal-fired boilers represent significant economic assets for their owners and operators. Construction materials used are high value, such as stainless steel for certain ductwork and equipment, and boilers are designed to last for 20 to 30 years or more. Improving coal quality preserves the value of this long-term investment.[25] However, the environmental and private benefits associated with improving coal quality must be compared with the costs, including the environmental costs of washing and processing coal. Actual costs and cost-effectiveness of improved coal quality will vary according to the power plant and its specific operating conditions.

As noted above, the Waymel and Hatt study assessed the costs and benefits of improving coal quality for a hypothetical 500-MW coal plant, with a heat rate of 10,000 BTU per kWh, burning bituminous coal. In addition to the results noted above, they reported that delivered coal costs would increase from $41.50 per ton (for coal with a heating value of 11,900 BTU/lb) to $46.50 per ton for the washed coal (with a heating value of 13,300 BTU/lb), leading to an increase in annual fuel costs of $200,000. However, the plant operator would realize a net annual savings of $710,000 per year, attributable to $450,000 in savings from increased boiler efficiency, $230,000 in savings from reduced ash disposal, and $230,000 from improved coal handling. On a net output basis, fuel costs were forecast to decline slightly, from 17.44 mil/kilowatt (kW) to 17.25 mil/kW.[26] Savings were also expected (but not quantified) from extended boiler and equipment life.

The ADB survey, also cited above, found that by reducing ash content from 41 percent to 34 percent, operation and maintenance costs declined by 20 percent and overall capital investment in the power plant could be reduced 5 percent.[27]

The IEA also published detailed results in conjunction with the above-mentioned survey.[28] Changes in coal quality were evaluated in general, and several case-specific examples were provided. The general trends in coal quality were evaluated for a 1000-MW plant, with a 65-percent capacity factor, a 10,000 BTU/kWh heat rate, a coal heating value of 12,000 BTU/lb, an ash content of 10 percent, and a fuel cost of $35/ton. Changing the quality of the coal burned by increasing the ash content 10 percent, increasing moisture content by 5 percent, and decreasing heating value by 15 percent resulted in a higher heat rate, and a negative cost impact of $4.46 million/year (1986$).

Results of other case studies also reflect significant cost effects from poor quality coal. The Tennessee Valley Authority (TVA) improved coal quality at its Cumberland power plant (two units, each at 1300 MW) over the period from 1977 to 1986. TVA found that its operating and maintenance costs decreased on average by $15 million per year. The largest change in coal quality was decreasing the ash content from 15.2 percent to 9.2 percent.[29] Sulfur content also decreased from 3.5 percent to 2.8 percent, and heating value increased from 10,712 BTU/lb (24.9 MJ/kg) to 11,635 BTU/lb (27.1 MJ/kg).

The Southern Company, which operates several coal-fired plants in the Southeastern United States, also analyzed its operating and maintenance costs. Southern found that increasing the ash content from 15 percent to 20 percent increased waste disposal costs, maintenance costs, and

25 It must be acknowledged, however, that even with higher quality coal, boiler design is still critical to the efficient operation of a power plant. Boiler design life is predicated on adherence to good fluid dynamics and heat transfer principles. Layout of the plant's ductwork and piping aims to minimize turns and bends and have large diameter ducts to minimize pressure drops, to maximize the thermal efficiency of the plant, and to avoid extra energy demand just to move flue gases from one point to another. Critical to this are well-mixed flue gases, which depend on adequate retention time in the combustion chamber to complete chemical reactions, achieve maximum heat transfer, and minimize the formation of air pollutants. Well-mixed flue gases also ensure that duct velocities are uniform from top to bottom and side to side. Doing so helps to assure that flue gas temperatures are as uniform as possible. Flue gas hot spots can cause duct deformation and flue gas cold spots can cause corrosion if the temperatures drop below the acid dew point.

26 Waymel & Hatt, supra footnote 8.

27 Supra footnote 11.

28 Skorupska, N. (1993). *Coal Specifications - Impact on Power Station Performance*. London: IEA. IEACR/52.

29 Ibid, page 75.

Figure 4-1

Coal Characteristics by Coal Type

	Higher Heating Value (kJ/kg)	Moisture Content (%wt)	Carbon Content (%wt)	Ash Content (%wt)	Sulfur Content (%wt)	Minemouth Coal Cost (2005 $/ton)
Anthracite	30,000[a]-31,500[b]	2.1[b]-12[a]	72[a]-87[b]	6.9[b]-11[a]	0.5[b]-0.7[a]	44-87[e]
Pittsburgh #8	30,800[c]-31,000[d]	1.1[d]-5.13[c]	73[d]-74[c]	7.2[c]-13[d]	2.1[c]-2.3[d]	45-55[e]
Illinois #6	25,400[c]-25,600[d]	8.0[d]-13[c]	60[d]-61[c]	11[c]-14[d]	3.3[c]-4.4[d]	32-39[e]
Chinese Coal	19,300-25,300[f]	3.3-23[f]	48-61[f]	28-33[f]	0.4-3.7[f]	N/A
Indian Coal	13,000-21,000[g]	4[g]-15[f]	30-50[h]	30-50[g]	0.2-0.7[g]	14-19[g]
WY Powder River Basin	19,400[c]-19,600[d]	28[d]-30[c]	48[c]-49[d]	5.3[c]-6.3[d]	0.37[c]-0.45[d]	6-17[e]
Texas Lignite	14,500[i]-18,300[j]	30[j]-34[i]	38[i]-44[j]	9[j]-14[i]	0.6[j]-1.5[i]	14[k]-15[l]
ND Lignite	14,000[c]-17,300[d]	32[d]-33[c]	35[c]-45[d]	6.6[d]-16[c]	0.54[d]-1.6[c]	9[l]

a Eberle, J.S., Garcia-Mallol, A.J., Simmerman, AM, “Advanced FW Arch Firing: NOXReduction in Central Power Station,” WPS Power Development, Inc. & Foster Wheeler Power Group, Inc., Presented at Pittsburgh Coal Conference, Pittsburgh, PA, Sept. 2002.

b Edward Aul & Associates, lnc., & E.H. Pechan & Associates, Inc., “Emission Factor Documentation for AP-42 Section 1.2 Anthracite Coal Combustion,” US EPA, Research Triangle Park, NC, 1993.

c Integrated Environmental Control Model, Carbon Sequestration Edition, IECM-cs 5.02, Carnegie-Mellon University, 2005.

d US Department of Energy, OFE/NETL “Carbon Capture and Sequestration Systems Analysis Guidelines,” Washington, D.C, April 2005.

e US Department of Energy, Energy Information Administration, “Coal News and Markets,” webpage, downloaded 11/30/05 from http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html

f Oskarsson, Karin, et al., “A planner’s guide for selecting clean-coal technologies for power plants,” Washington, DC: The World Bank, 1997.

g International Energy Agency, “Coal in Energy Supply of India,” OECD/IEA, Paris, France, 2002.

h Ohio Supercomputer Center, “Anthropogenic Emissions from Energy Activities in India: Generation and Source Characterization” website, downloaded 11/30/05 from http://www.osc.edu/research/pcrm/emissions/coal.shtml.

i San Filipo, John R., “US Geological Survey Open-File Report 99-301,” US Geological Survey, Reston, VA, 1999.

j Gray, D., et al., “Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite,” NETL, Falls Church, VA, 2004.

k US Department of Energy, Energy Information Administration, “Coal Industry Annual, 2000,” Washington, D.C. 2000.

l US Department of Energy, Energy Information Administration, “Average Open Market Sales Price of Coal by State and Coal Rank,” 2004, webpage, downloaded 11/30/05 from http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html.

forced outages due to ash.[30]

A review of publicly available information on coal washing often finds an emphasis on the benefits to coal *producers* from washed coal (i.e., they can fetch a higher price for their product). Coal with lower sulfur and ash content is indeed more expensive than coal with higher sulfur and ash content.[31] The Massachusetts Institute of Technology study, "The Future of Coal," includes Figure 4-1, which illustrates the influence of these and other variables on the price of coal.[32]

Table 4-2 below is an example of the coal commodity spot price data available from the EIA. This table illustrates the price differences based on both heating value and sulfur content. Low-sulfur Central Appalachian coal represents the highest price, whereas low-BTU Powder River Basin coal is lowest.

The EIA also summarizes the prices fetched by various coal ranks. Table 4-3 on the following page presents data for 2012. Regardless of the mine location, bituminous coals sold for much higher prices than sub-bituminous coals and lignite. Anthracite is mined in Pennsylvania; its high heating value makes it attractive as a coking or metallurgical coal.

7. Other Considerations

As is the case for many other pollution control options, beneficiation has the potential to increase the utilization of a given power plant. The ADB survey found that for each 10-percent reduction in ash content, the plant use factor (or capacity factor) can increase up to six percent as forced outages and maintenance issues related to tube leaks, the economizer, and associated components are reduced. Thus, the potential exists for the gross annual emissions of a given power plant to increase as a result of beneficiation, despite decreases in the emissions *rates*. Any increases in plant

Table 4-2

Average Weekly Coal Commodity Spot Prices (Per Short Ton)[33]

Week Ended	Central Appalachia 12,500 Btu, 1.2 SO_2	Northern Appalachia 13,000 Btu, <3.0 SO_2	Illinois Basin 11,800 Btu, 5.0 SO_2	Powder River Basin 8,800 Btu, 0.8 SO_2	Uinta Basin 11,700 Btu, 0.8 SO_2
18 January 2013	$68.05	$62.10	$47.90	$10.15	$35.85
25 January 2013	$68.05	$62.10	$47.90	$10.15	$35.85
01 February 2013	$66.50	$62.10	$47.90	$10.15	$35.85
08 February 2013	$66.50	$62.10	$47.90	$10.15	$35.85
15 February 2013	$66.50	$62.10	$47.90	$10.25	$35.85

30 Supra footnote 29 at page 75.

31 Coal is priced both on a dollars per ton and a dollars per MMBtu basis. The price itself is based on several factors, including its rank, how it is mined, and its quality. Coal mined through subsurface means is more expensive than coal mined at the surface (e.g., mountain top removal).

32 Massachusetts Institute of Technology. (2007). *The Future of Coal - Options for a Carbon Constrained World.* Available at: http://web.mit.edu/coal/.

33 The historical data file of spot prices is proprietary and cannot be released by EIA. This sample table is printed with permission from SNL Energy (http://www.snl.com/Sectors/Energy/Default.aspx). Note: Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt quarter." The prompt quarter is the quarter following the current quarter. For example, from January through March, the second quarter is the prompt quarter. Starting on April 1, July through September define the prompt quarter.

Table 4-3

Average Sales Price of Coal by State and Coal Rank, 2012 (Dollars Per Short Ton)[34]

Coal-Producing State	Bituminous	Sub-bituminous	Lignite	Anthracite	Total
Alabama	106.57	-	-	-	106.57
Alaska	-	w	-	-	w
Arizona	w	-	-	-	w
Arkansas	w	-	-	-	w
Colorado	w	w	-	-	37.54
Illinois	53.08	-	-	-	53.08
Indiana	52.01	-	-	-	52.01
Kentucky Total	**63.12**	**-**	**-**	**-**	**63.12**
Kentucky (East)	75.62	-	-	-	75.62
Kentucky (West)	48.67	-	-	-	48.67
Louisiana	-	-	w	-	w
Maryland	55.67	-	-	-	55.67
Mississippi	-	-	w	-	w
Missouri	w	-	-	-	w
Montana	w	17.6	w	-	18.11
New Mexico	w	w	-	-	36.74
North Dakota	-	-	17.4	-	17.4
Ohio	47.8	-	-	-	47.8
Oklahoma	59.63	-	-	-	59.63
Pennsylvania Total	**72.57**	**-**	**-**	**80.21**	**72.92**
Pennsylvania (Anthracite)	-	-	-	80.21	80.21
Pennsylvania (Bituminous)	72.57	-	-	-	72.57
Tennessee	73.51	-	-	-	73.51
Texas	-	-	19.09	-	19.09
Utah	34.92	-	-	-	34.92
Virginia	109.4	-	-	-	109.4
West Virginia Total	**81.8**	**-**	**-**	**-**	**81.8**
West Virginia (Northern)	63.34	-	-	-	63.34
West Virginia (Southern)	91.4	-	-	-	91.4
Wyoming	-	14.24	-	-	14.24
US **Total**	**66.04**	**15.34**	**19.6**	**80.21**	**39.95**

- = No data reported.

w = Data withheld to avoid disclosure.

Note: An average sales price is calculated by dividing the total free onboard rail/barge value of the coal sold by the total coal sold. Excludes mines producing less than 25,000 short tons, which are not required to provide data. Excludes silt, culm, refuse bank, slurry dam, and dredge operations. Totals may not equal sum of components because of independent rounding.

34 US EIA. (2013). Annual Coal Report 2012. Available at: http://www.eia.gov/coal/annual/pdf/acr.pdf.

use factor could of course allow for decreased generation and emissions from some other power plant. These factors will need to be evaluated in the context of the EPA's Clean Power Plan proposal, where heat rate improvements are the cornerstone of Building Block 1.

Using scarce water resources to improve coal quality may not be justified in some geographic areas, and it may be better to improve coal quality at the power plant or at some intermediate site between the mine mouth and the plant, where water resources are more plentiful and can be reused. Also, washing coal creates a need to impound the residual slurry from the washing process itself. Slurry storage ponds give rise to the risk for contamination of local waterways and ground water if the containment ponds leak. This is a serious environmental consideration and requires careful oversight by regulators.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on coal beneficiation:

- ADB. (1998). *India: Implementation of Clean Technology through Coal Beneficiation.* Project number 26095, prepared for the ADB by Montan-Consulting GMBH in association with International Economic and Energy Consultants and CMPDI International Consultants, India. Available at: http://www2.adb.org/documents/reports/Consultant/IND/26095/26095-ind-tacr.pdf.
- Pacyna, J.,Sundseth, K., Pacyna, E. G., Jozewicz, W., Munthe, J., Belhaj, M. & Aström, S. (2010). An Assessment of Costs and Benefits Associated with Mercury Emission Reductions from Major Anthropogenic Sources. *Journal of the Air & Waste Management Association.* 60:3, 302-315, doi: 10.3155/1047-3289.60.3.302. Available at: http://dx.doi.org/10.3155/1047-3289.60.3.302.
- Rubin, E., Chen, C., & Rao, A. B. (2007). Cost and Performance of Fossil Fuel Power Plants with CO_2 Capture and Storage. *Energy Policy.* 35, 4444–4454. Available at: http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2007/2007b%20Rubin%20et%20al,%20Energy%20Policy%20%28Mar%29.pdf
- Skorupska, N. (1993). *Coal Specifications - Impact on Power Station Performance.* London: IEA. IEACR/52.
- Waymel, E., & Hatt, R. (1987). *Improving Coal Quality: An Impact on Plant Performance.* Lexington, KY: Island Creek Corporation. (Estimated publication date based on references in the paper.) Available at: http://www.coalcombustion.com/PDF%20Files/Improving%20Coal%20Quality.pdf.

9. Summary

Coal beneficiation has the potential to provide economic, energy, and environmental benefits for some units depending on unit-specific design. Even small reductions in coal consumption on the order of one to two percent, for the same generating output, improve the profit margin of the power plant, extend the life of pollution controls, reduce the quantity of water and solid waste discharged, and reduce GHG, criteria pollutant, and mercury emissions. Water constraints in certain regions will favor dry beneficiation processes over wet.

7. Pursue Carbon Capture and Utilization or Sequestration

Carbon capture and utilization and/or storage refers to a two-pronged approach to reducing carbon dioxide (CO_2) emissions from fossil-fired electric generating units (EGUs) and other CO_2-emitting facilities. At EGUs, CO_2 can be collected prior to or after combustion of fuel using one of three types of capture: pre-combustion, oxy-combustion, or post-combustion. Following *capture*, the CO_2 can be compressed and transported to an injection site for underground *storage,* or it can be *utilized* for productive purposes.

CO_2 is primarily considered a waste product, but there are a limited number of exceptions in which it can be used for productive purposes. These exceptions include using CO_2 for enhanced oil recovery (EOR); producing consumer products like carbonated beverages; and growing algae that can be used for biofuels, animal feed, or chemical production.[1] Of these options, EOR is the most technologically mature and has the most working examples demonstrating its feasibility for widespread use. The demand for CO_2 in consumer products, on the other hand, is currently very limited and in most cases the gas would eventually be emitted as the product is used or consumed. Using CO_2 to grow algae is a promising option that is the subject of numerous demonstration projects but is not yet commercially deployed at full scale. Therefore, this chapter focuses primarily on the combination of carbon capture with underground storage or with EOR.

Pre-combustion capture is a technology applicable to Brayton cycle[2] facilities including integrated gasification combined-cycle (IGCC) plants. IGCC plants gasify solid fuels such as coal and petroleum coke[3] to produce "synthesis" gas or "syngas," a combustible fuel whose main constituents are hydrogen, carbon monoxide (CO), and CO_2. Carbon capture removes the latter two components of syngas, leaving primarily hydrogen to be burned for electricity production.

As shown in Figure 7-1, following gasification and gas cleanup in the particle remover, syngas is sent to a shift reactor that "shifts" CO to CO_2, hence the need for steam at this step to add the additional oxygen atom and create CO_2 out of CO. Next, the sulfur content in syngas, in particular hydrogen sulfide or acid gas, must be removed.[4] Finally, the CO_2 can be separated from the syngas and then compressed for transport and storage.

Oxy-combustion capture creates a highly concentrated stream of CO_2 by firing fuel in an oxygen-rich environment.

1 For more information regarding the use of CO_2 to grow algae, refer generally to the Algae Biomass Organization website at: http://www.algaebiomass.org/. A summary of demonstration projects is available at: http://www.algaebiomass.org/wp-content/uploads/2010/06/ABO_project_book_lo-res_July2013.pdf.

2 The Brayton cycle (or Joule cycle) represents the operation of a gas turbine engine. The cycle consists of four processes: compression of an inlet stream (air); constant pressure fuel combustion; expansion and exhaust through a turbine and/or exhaust nozzle, turning a generator (and also driving the compressor); and cooling the air back to its initial condition. See: http://web.mit.edu/16.unified/www/SPRING/propulsion/notes/node27.html

3 Petroleum coke is a byproduct of oil refining.

4 Figure 7-1 shows gypsum as the byproduct of sulfur removal, but in order to recover gypsum from an IGCC plant a hydrogen sulfide furnace and limestone-gypsum absorber are necessary. Onishi, H. (2004, September). *250 MW Air-Blown IGCC Demonstration Plant in Japan and its Future Prospect.* 19th World Energy Congress.

Figure 7-1

Pre-Combustion Capture at an IGCC Plant[5]

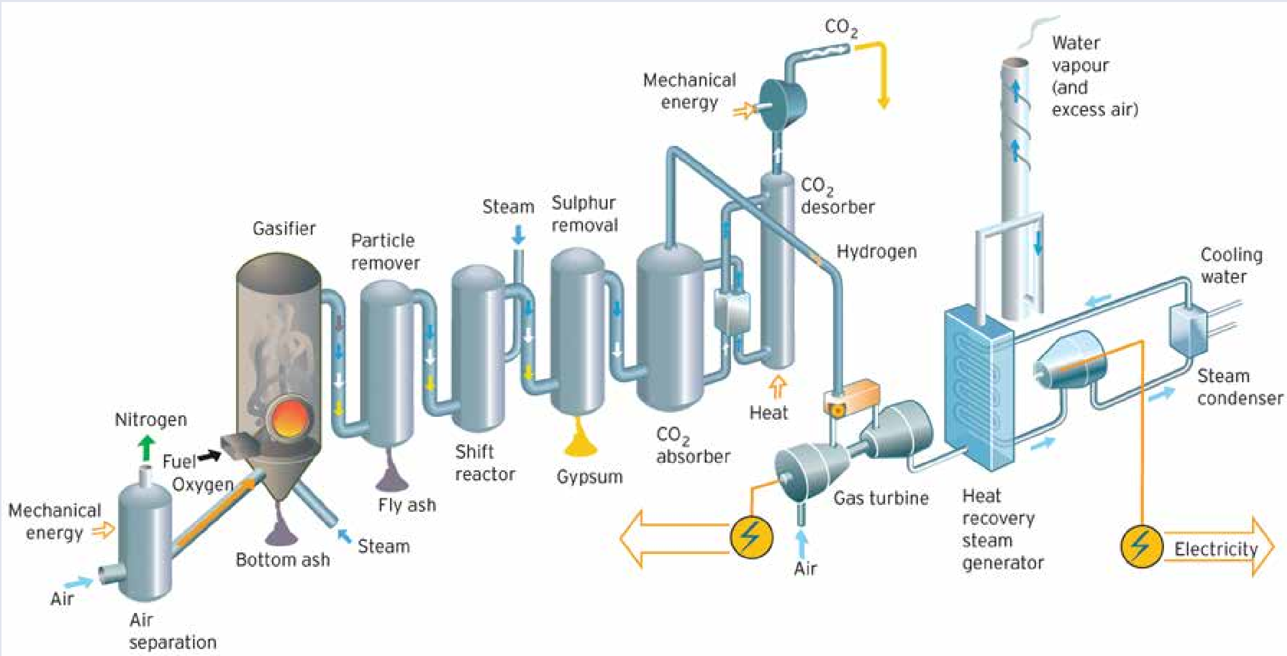
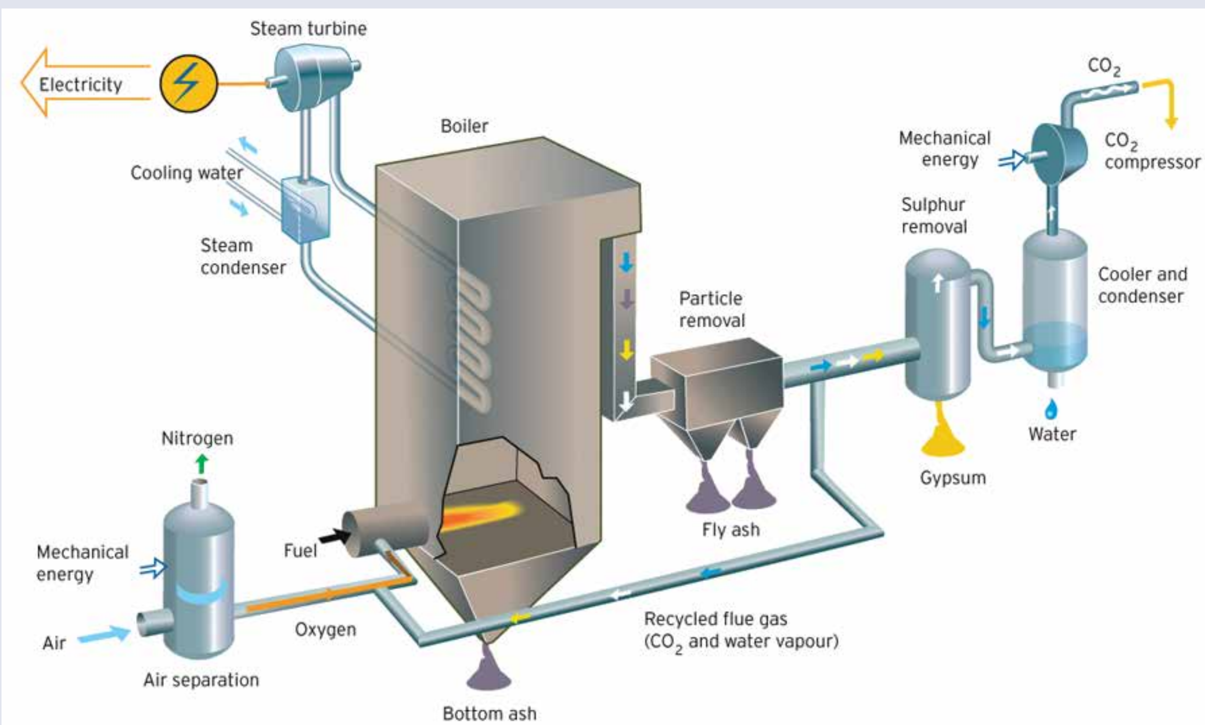


Figure 7-2

Oxy-Combustion Capture at a Pulverized Coal Plant[6]

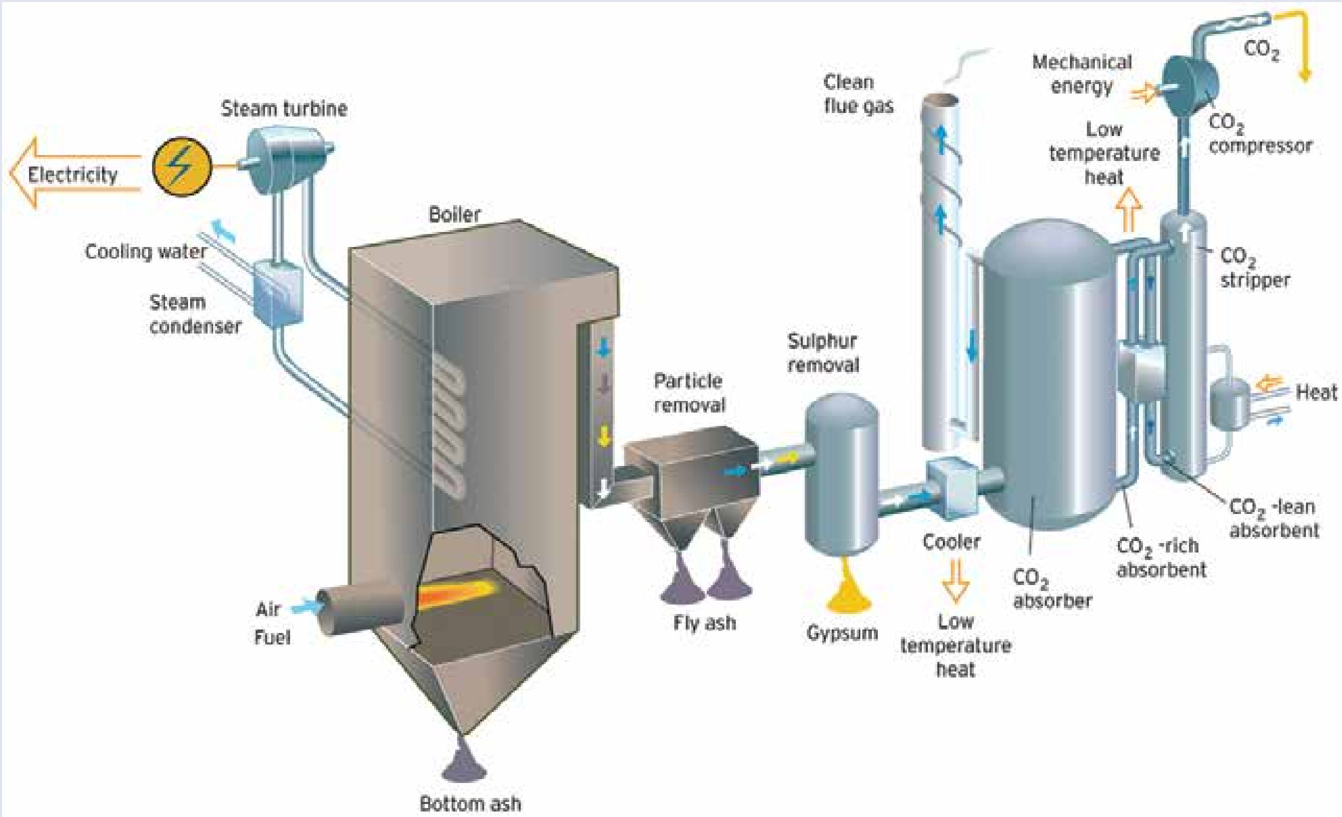


5 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Pre-combustion%20Capture%20Process_Vattenfall.jpg

6 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Oxyfuel%20Combustion%20Capture%20Process_Vattenfall.jpg

Figure 7-3

Post-Combustion Capture at a Pulverized Coal Plant[7]



The resulting flue gas is approximately 70 percent CO_2.

As shown in Figure 7-2, ash and sulfur emissions must be removed, as in typical pulverized coal plant operations. In addition, the water content of the flue gas must be reduced before the CO_2 is ultimately compressed for transport.

Because of the expense associated with oxy-combustion (discussed in Section 6) and because there are only three operating IGCC plants in the United States,[8] the focus of most of this chapter is on carbon storage coupled with post-combustion capture. Post-combustion capture is typically envisioned on pulverized coal plants, as shown in Figure 7-3, but could also occur on the back end of natural gas-fired power plants.

Post-combustion capture strips the flue gas of its CO_2 using ammonia or an amine as the absorbent and then compresses the CO_2 for transport and storage. The maximum percentage of CO_2 that can be captured by any of these technologies is 90 percent. But regardless of how the CO_2 is captured, it must be compressed to its supercritical phase for transport. In its supercritical state, the CO_2 has properties of both a gas and a liquid.

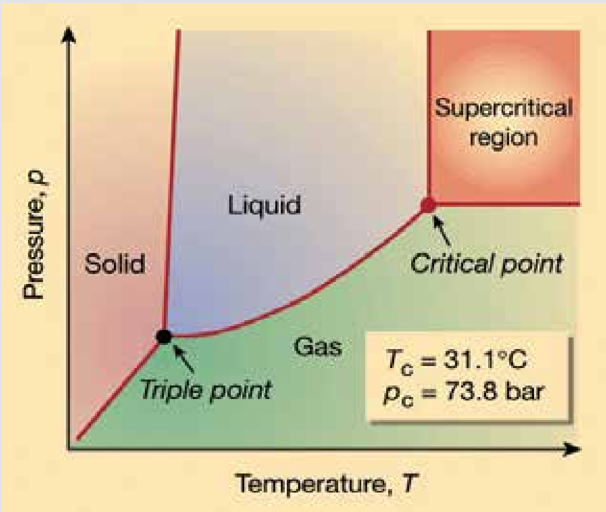
To reach its supercritical phase, the CO_2 is compressed in multiple stages. The minimum temperature and pressure at which CO_2 reaches its supercritical state are 31.1 degrees Celsius and 73.8 bar as shown in Figure 7-4. Compression to this phase is necessary to transport large volumes of CO_2, and also to inject the CO_2. Much more underground

7 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Post-combustion%20Capture%20Process_Vattenfall.jpg

8 The operating IGCC plants are Wabash River and Edwardsport in Indiana and Polk Power in Florida. The Kemper County IGCC plant is under construction in Mississippi. The Texas Clean Energy Project, a coal-fired IGCC plant, and the Hydrogen Energy California Project, a petroleum coke-fired IGCC plant, are also in the planning stages but not yet under construction.

Figure 7-4

CO_2 Phase Diagram[9]



volume is needed to store CO_2 in the gas phase than in the supercritical phase.[10]

There are three main types of geologic formations thought to provide sufficient capacity to store large volumes of CO_2: saline aquifers, oil and gas reservoirs, and unmineable coal seams. Saline aquifers consist of layers of sedimentary porous and permeable rocks saturated with salty water, called brine.[11] Saline aquifers are thought to have the largest potential for carbon storage because they are so widespread.

Oil and gas reservoirs are less plentiful than saline aquifers, but they are generally better understood owing to years of oil and gas production. These reservoirs may be used purely for sequestration, but often they are used for EOR as well. In EOR, CO_2 is injected into a reservoir to stimulate oil production. Because CO_2 is miscible[12] with oil, it makes the oil more fluid and pushes it toward the producing well.[13] CO_2-EOR can produce approximately 35 percent of the residual oil in a reservoir.[14]

Coal seams may be considered unmineable for geologic, economic, or other reasons. Coal seams have less potential storage capacity than saline aquifers or oil and gas reservoirs, but they do have the possible co-benefit of enhancing methane production while trapping CO_2. Methane is the primary consituent of natural gas. Coal and methane are often found together; methane resides on the surface of the coal, a phenomenon known as adsorption.[15] However, because coal preferentially adsorbs CO_2 over methane, the coal releases the methane for production from the seam when CO_2 is present.

Whether storage in a saline aquifer, hydrocarbon reservoir, or coal seam is contemplated, characterization of the formation is extremely important. Among the characteristics that must be determined are *porosity* and *permeability.* Porosity is the "percentage of pore volume or void space… that can contain fluids."[16] Permeability is "the ability, or measurement of a rock's ability, to transmit fluids [measured in darcys[17]]."[18] A permeable formation typically has many large pores that are well connected.[19] Porosity and permeability help determine another very important aspect of any storage formation, *injectivity.* Injectivity is "the rate and pressure at which fluids can be pumped into the treatment target without fracturing the formation."[20] Although fractures

9 Leitner, W. (2000, May 11). Green Chemistry: Designed to Dissolve. *Nature 405,* 129–130. Available at: http://www.nature.com/nature/journal/v405/n6783/fig_tab/405129a0_F1.html

10 US Department of Energy National Energy Technology Laboratory. (2010, September). *Geologic Storage Formation Classifications: Understanding Its Importance and Impacts on CCS Opportunities in the United States,* p. 11. Available at: www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/BPM_GeologicStorageClassification.pdf

11 US Department of Energy National Energy Technology Laboratory. (2012). *Carbon Utilization and Storage Atlas.* Available at: http://www.netl.doe.gov/research/coal/carbon-storage/atlasiv

12 A "miscible" fluid can be mixed with other fluids to form a homogenous solution.

13 Hyne, N. (2001). *Nontechnical Guide to Petroleum Geology, Exploration, Drilling, and Production.* Tulsa, OK: PennWell.

14 Supra footnote 13

15 Nazaroff, W., & Alvarez-Cohen, L. (2001). *Environmental Engineering Science.* New York: Wiley.

16 Schlumberger. (2011). *Porosity.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/en/Terms/p/porosity.aspx

17 A rock formation with a permeability of 1 darcy permits a flow of 1 cm^3/second of a fluid with viscosity of 1 under a pressure gradient of 1 atmosphere/cm acting across an area of 1 cm^2.

18 Schlumberger. (2011). *Permeability.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/en/Terms/p/permeability.aspx

19 Ibid.

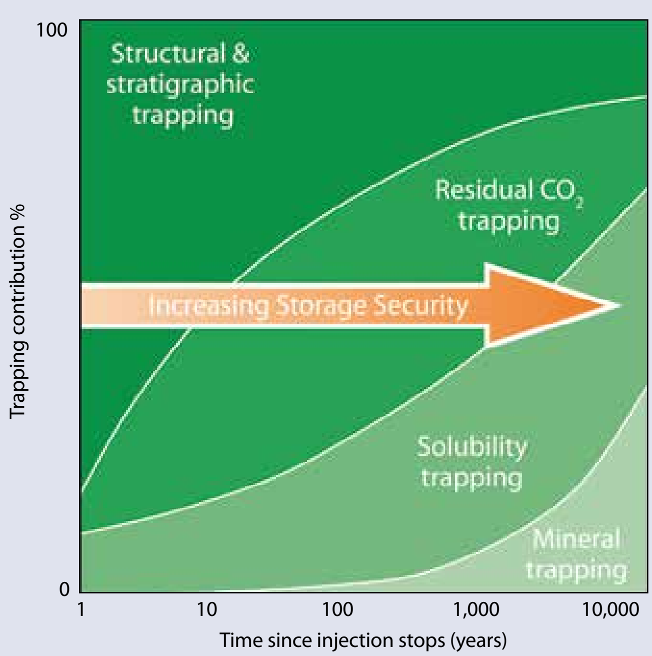
20 Schlumberger. (2011). *Injectivity Test.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/Display.cfm?Term=injectivity%20test

in a storage formation would seem to offer additional pathways for the CO_2 to move, they can also provide pathways for the CO_2 to escape to the surface and thereby compromise the integrity of the storage formation.

When CO_2 is injected underground, several mechanisms may work to keep it underground. First, because the other fluids in saline aquifers and oil and gas reservoirs are less buoyant than CO_2, a low permeability seal or caprock is necessary to prevent CO_2 from migrating upward.[21] This is known as "primary" or "buoyant" trapping.[22] "Secondary" trapping mechanisms include: dissolving CO_2 in water (solubility trapping); trapping CO_2 by capillary forces between pore spaces (residual trapping); precipitation of CO_2 in a carbonate compound (mineral trapping); and trapping CO_2 in coal seams (adsorption trapping, discussed previously).

Figure 7-5

Trapping Mechanisms Occur on Different Time Frames[23]



Each trapping mechanism happens on a different time scale (Figure 7-5).

Primary trapping (also known as "structural" or "stratigraphic" trapping) occurs immediately, but residual trapping is thought to happen after injection stops.[24] Mineral trapping, in particular, is believed to occur on much longer time frames.

In 2012, the United States Geological Survey (USGS) published its estimate of the technical CO_2 geologic storage potential in the United States. USGS's assessment of the CO_2 storage resource was conducted using "present-day geological and engineering knowledge and technology for CO_2 injection into geologic formations."[25] It did not incorporate economic or engineering constraints.

The areas analyzed by the USGS are shown in the map in Figure 7-6. The lighter grey areas were evaluated by the USGS but were not assessed. The resulting storage estimates predicted that the most storage capacity lies in the Coastal Plains (1900 gigaton [Gt]), followed by the Rocky Mountains and Northern Great Plains and Alaska (270 Gt each), and the Eastern Mid-Continent (230 Gt). All other regions were estimated to have 150 Gt or less of storage potential, for a total mean storage potential of 3000 Gt. The USGS's assessment included saline aquifers and oil and gas reservoirs, but not unmineable coal seams because the USGS could find no definition to determine which coals seams are unmineable.[26]

The USGS's methodology accounted for two trapping mechanisms: buoyant and residual. The residual trapping resource was divided into three classes based on reservoir permeability: class 1 (formations with permeability greater than 1 darcy [D]); class 2 (formations with permeability between 1 millidarcy [mD] and 1 D); and class 3 (formations with permeability of less than 1 mD).

21 Benson, S. M., & Cole, D. R. (2008). CO_2 Sequestration in Deep Sedimentary Formations. *Elements 4(5),* 325–331. doi: 10.2113/gselements.4.5.325 Available at: http://elements.geoscienceworld.org/content/4/5/325.short

22 Supra footnote 11.

23 Metz, B., Davidson, O., de Coninck, H., Loos, M., & Meyer, L., eds. (2005). *Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambrige, United Kingdom: Cambridge University Press, pp. 195–276. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

24 Supra footnote 21.

25 Brennan, S. T., Burruss, R. C., Merrill, M., D.; Freeman, P. A., & Ruppert, L. F. (2010). *A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage.* USGS Open-File Report 2010–1127. Available at: http://pubs.usgs.gov/of/2010/1127

26 US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Results.* US Geological Survey Circular 1386. Available at: http://pubs.usgs.gov/circ/1386/

Figure 7-6

Eight Regions Used in USGS's Geologic Storage Resource Assessment[27]

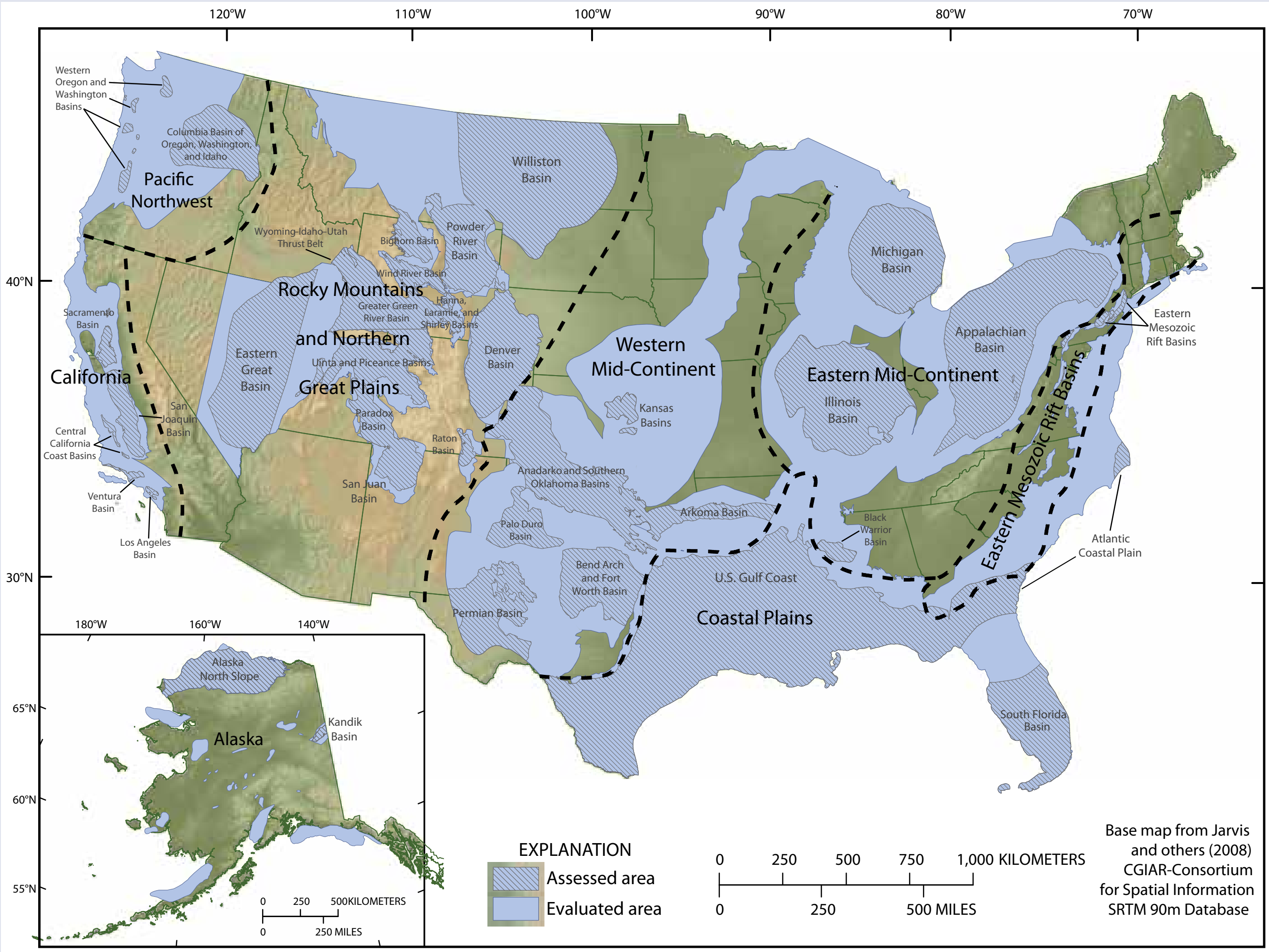
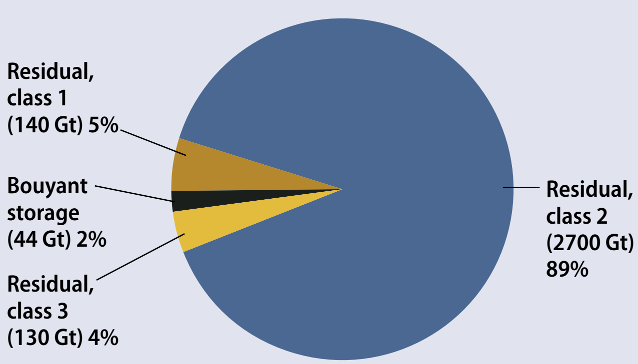


Figure 7-7

Geologic Storage Resource by Trapping Mechanism and Permeability Class[28]



The USGS found residual trapping in class 2 formations to be the overwhelming driver of total nationwide storage capacity, accounting for 89 percent of the resource (Figure 7-7).

Figure 7-8 depicts a sample cross-section of a storage formation such as those the USGS analyzed in this assessment.

The blue areas show the parts of the formation where buoyant trapping occurs. The green depicts the areas where residual trapping would have to be relied upon. Simply from a visual perspective, it's clear that residual trapping dramatically increases the volume available for CO_2 storage.

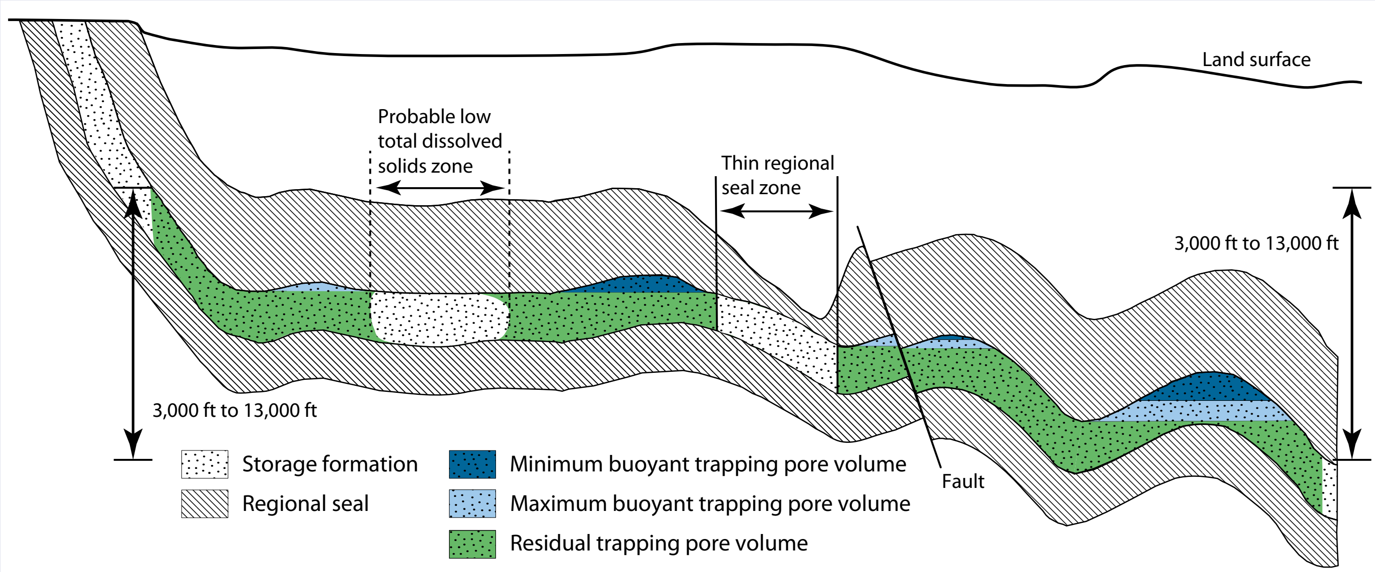
It is important to note, therefore, that "storage efficiencies

27 Supra footnote 26.

28 Ibid.

Figure 7-8

Cross-Section of a Sample Storage Formation Showing the Distribution of Pore Volume Between Buoyant and Residual Trapping[29]



associated with residual trapping are poorly understood," because no commercial-scale injection projects using this trapping mechanism have been undertaken.[30] In 2013, the United States emitted approximately 5.4 Gt of energy-related CO_2.[31] If carbon storage is to play a major role in addressing climate change, then secondary trapping mechanisms must be dependable. Relying on buoyant trapping alone would only provide enough capacity to store eight years' worth of the nation's CO_2 emissions.

2. Regulatory Backdrop

In the United States, no state or federal law has mandated the application of carbon capture and sequestration (CCS) to any power plant. However, partial CCS was proposed by the US Environmental Protection Agency (EPA) to be the Best System of Emission Reduction for new utility boilers and IGCC units under the agency's proposed carbon pollution standards for these sources (a.k.a. the proposed "111(b) rule," because it is based on the EPA's authority under section 111(b) of the Clean Air Act). The EPA defined partial CCS as achieving a CO_2 emissions rate of 1100 pounds per gross megawatt-hour (MWh). A new source would likely use a continuous emissions monitoring system to measure the plant's mass CO_2 emissions and demonstrate compliance. With respect to *existing* power plants and the Clean Power Plan that the EPA proposed in June 2014, the EPA determined that CCS is *not* an adequately demonstrated and cost-effective measure for reducing CO_2 emissions on a national scale:

> While the EPA found that partial CCS is technically feasible for new fossil fuel-fired boilers and IGCC units, it is much more difficult to make that determination for the entire fleet of existing fossil fuel-fired EGUs. Developers of new generating facilities can select a physical location that is more amenable to CCS – such as a site that is near an existing CO_2 pipeline or an existing oil field. Existing sources do not have the advantage of pre-selecting an appropriate location. Some existing facilities are located in areas where CO_2 storage is not geologically favorable and are not near an existing CO_2 pipeline. Developers of new facilities also have the advantage of integrating the partial

29 Blondes, M., Brennan, S., Merrill, M., Buursink, M., Warwick, P., Cahan, S., Cook, T., Corum, M., Craddock, W., DeVera, C., Drake II, R., Drew, L., Freeman, P., Lohr, C., Olea, R., Roberts-Ashby, T., Slucher, E., & Varela, B. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Methodology Implementation.* US Geological Survey Open-File Report 2013–1055. Available at: http://pubs.usgs.gov/of/2013/1055/

30 Supra footnote 25.

31 US Energy Information Administration. (2014, June). *Monthly Energy Review.* Available at: http://www.eia.gov/totalenergy/data/monthly/archive/00351406.pdf

CCS system into the original design of the new facility. Integrating a retrofit CCS system into an existing facility is much more challenging. Some existing sources have a limited footprint and may not have the land available to add partial CCS system. Integration of the existing steam system with a retrofit CCS system can be particularly challenging.[32]

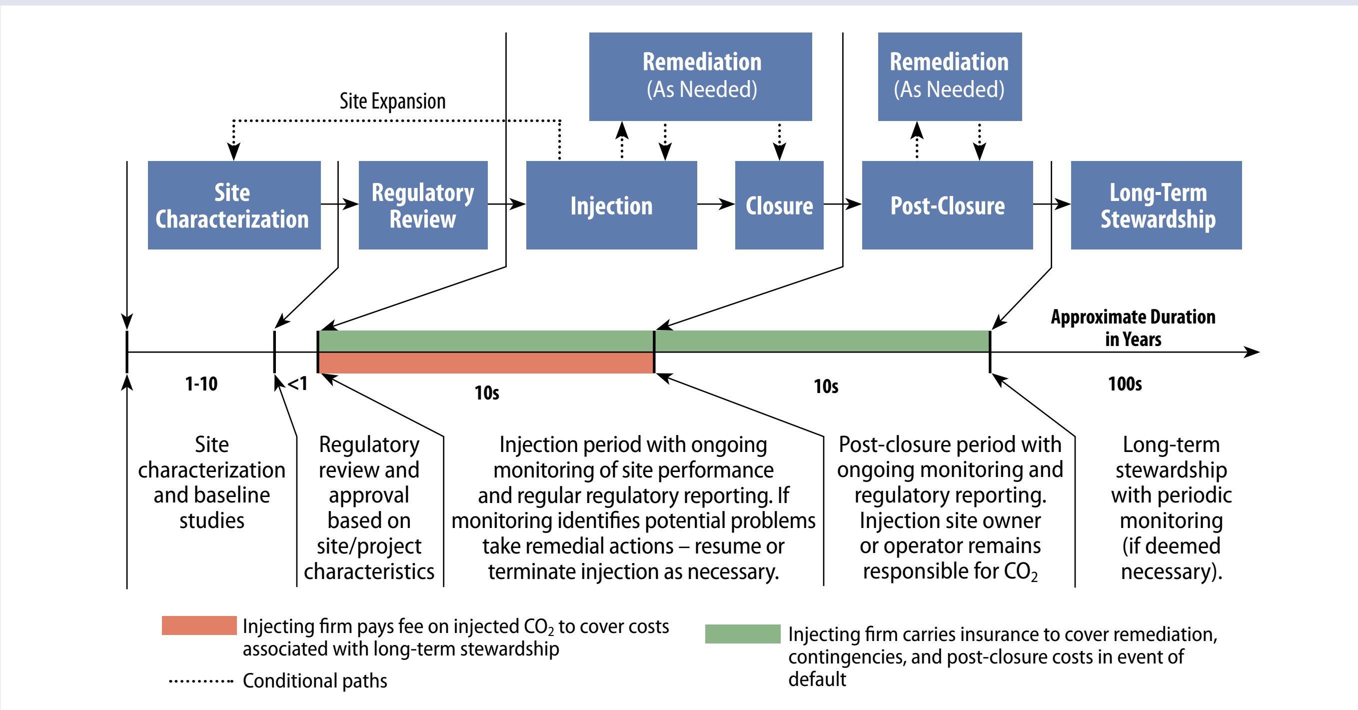
Although the EPA decided not to include CCS as part of the Best System of Emission Reduction for existing power plants, the agency notes that "at some existing facilities, the implementation of partial CCS may be a viable greenhouse gas (GHG) mitigation option and some utilities may choose to pursue that option" for complying with the 111(d) rule.[33] No specific mechanism for measuring the impact of CCS at existing facilities was included in the EPA's proposal, but all affected EGUs would be equipped with CO_2 continuous emissions monitoring systems. With respect to both the 111(b) and 111(d) proposals, the EPA appears to have based its findings about the viability of CCS on a review of geologic storage and EOR technical potential, without consideration of other potential utilization options, such as growing algae for biofuels.

It is worth noting that geologic storage of CO_2 is a fairly new field for regulation. Among the steps in carbon storage that need to be addressed through regulation are site characterization, site operations, closure, and long-term stewardship.[34]

As Figure 7-9 shows, each of these steps is likely to be

Figure 7-9

Phases of a Geologic Storage Project[35]



32 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures

33 Ibid.

34 Wilson, E., & Pollak, M. (2008). *Policy Brief: Regulation of Carbon Capture and Storage.* International Risk Governance Council. Available at: http://www.hhh.umn.edu/people/ewilson/pdf/regulation_carbon_capture_storage.pdf

35 Rubin, E. S., Morgan, M. G., McCoy, S. T., & Apt., J. (2007, May). *Regulatory and Policy Needs for Geological Sequestration of Carbon Dioxide.* Proceedings of US Department of Energy 6th Annual Conference on Carbon Capture and Sequestration. Available at: http://www.epp.cmu.edu/people/faculty/rubin/index.php?p=2007

multiyear. Site characterization is the process of identifying a potential site and confirming that it is suitable for carbon storage. The steps involved have been defined more conceptually than in terms of specific characteristics or analytical methodologies, owing to the lack of experience with carbon storage.[36] Regulation of injection would address such contingencies as release to the atmosphere, surface damage, and CO_2 migration beyond the intended storage formation.[37] The transition from post-closure to long-term stewardship is largely defined by who holds the responsibility to ensure that the injected CO_2 is retained in the storage formation. The authors of Figure 7-9 assume that long-term stewardship, which could last hundreds of years, will ultimately be taken over by the federal government because they "do not believe that there is any feasible way to assign long-term stewardship responsibility in perpetuity to any private entity, nor would private actors accept such responsibility."[38]

Missing from Figure 7-9 is the need for rules governing the ownership of pore space in the subsurface. Although surface property rights and subsurface mineral rights have been separable for many years in several areas of the United States, there is no clear precedent as to whether pore space rights belong to the surface owner, subsurface mineral rights owner, or neither.[39] Because CO_2 storage may interact with other subsurface activities such as produced water disposal, water recovery, hydrocarbon production, or natural gas storage,[40] resolving the question of who has access to pore space is important to the success of CCS projects.

To date, there are federal regulations governing injection, to a degree, but not other aspects of storage.

On July 25, 2011, the EPA finalized a rule establishing a permitting system for wells used in the geologic storage of CO_2.[41] The Federal Underground Injection Control (UIC) Class VI Program for Carbon Dioxide Geologic Sequestration will allow states and potential owners/operators of wells used in geologic storage to receive a permit from the appropriate EPA regional office. The federal government has primacy over this program until a state applicant submits and has its application approved by the EPA.[42] Thus far only North Dakota has submitted an application for primacy.[43]

The UIC program, however, was established under the Safe Drinking Water Act and, as such, it is aimed at preventing drinking water contamination, not at ensuring long-term storage of CO_2.[44] In addition, the UIC program does not cover injection in offshore formations.[45]

The CCSReg Project, a group of academics and lawyers exploring how to "best…implement an appropriate regulatory environment in the US for the commercialization of carbon capture and deep geological sequestration," has called for federal legislation to accomplish the following:

- Declare that sequestering CO_2 in geologic formations to mitigate the detrimental effects of climate change is in the public interest;
- Address the issue of access to and use of geologic pore space;
- Amend the Safe Drinking Water Act to direct UIC regulators to promulgate rules for geologic sequestration (GS) that:

36 Rodosta, T. D., Litynski, J. T., Plasynski, S. I., Hickman, S., Frailey, S., & Myer, L. (2011). US Department of Energy's Site Screening, Site Selection, and Initial Characterization for Storage of CO_2 in Deep Geological Formations. *Energy Procedia 4,* pp. 4664–4671. Available at: http://www.sciencedirect.com/science/article/pii/S1876610211007065

37 Supra footnote 35.

38 Ibid.

39 Wilson, E., & Klass, A. (2009, April). *Climate Change, Carbon Sequestration, and Property Rights.* University of Illinois Law Review, Vol. 2010, 2010 and Minnesota Legal Studies Research Paper No. 09-15. Available at: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1371755

40 Ibid.

41 Refer to the Federal Register at: http://www.gpo.gov/fdsys/pkg/FR-2011-09-15/pdf/2011-23662.pdf

42 Ibid.

43 Refer to the Vinson & Elkins law firm website at: http://climatechange.velaw.com/EPAIssuesGuidanceSDWAClassVIPrimacyApplicants.aspx

44 Pollak, M., & Wilson, E. (2009). Regulating Geologic Sequestration in the United States: Early Rules Take Divergent Approaches. *Environmental Science & Technology, 43(9)*, pp. 3035–3041. Available at: http://pubs.acs.org/doi/abs/10.1021/es803094f

45 Supra footnote 35.

  - Address all environmental, health, and safety issues associated with GS;
  - Are principally based on adaptive, performance-based standards, as opposed to design standards; and,
  - Include mechanisms to balance and resolve conflicts between multiple environmental objectives;
- Direct UIC regulators to coordinate with regulators in charge of GHG inventory accounting for the United States;
- Obligate GS project operators to contribute on the basis of their operating performance to a revolving fund to cover long-term stewardship; and
- Create an independent public entity (the Federal Geologic Sequestration Board) to approve and accept responsibility for appropriately closed GS sites.[46]

The CCSReg Project has also issued model legislation to cover these issues, but to date, Congress has taken no action. Meanwhile, several states have stepped in with legislation to address certain aspects of storage and transportation of CO_2.[47]

3. State and Local Implementation Experiences

In support of the proposed 111(b) GHG standards for new power plants, the EPA cited several examples of "currently operating or planned CO_2 capture or storage systems, including, in some cases, components necessary for coal-fired power plant CCS applications."[48] At the time the proposed rule was issued, there were no power plants in the United States or in the rest of the world that integrated commercial-scale CCS, but two carbon capture and EOR projects were under construction. One of them, the Boundary Dam Project in Saskatchewan, came online in October 2014 with an output of 110 MW. The project rebuilt an existing pulverized coal plant and retrofit it with a 90-percent post-combustion capture system at a cost of $1.35 billion.[49] The CO_2 captured at this facility is used in EOR at the Weyburn oil field.[50] The Kemper County IGCC project in Mississippi remains under construction, with commercial operation projected in mid 2016. It would capture approximately 65 percent of total CO_2 emissions and have a nominal output of 583 MW.[51] Kemper County has experienced schedule delays and cost increases that have pushed its in-service date into 2016 and raised the cost of the project to $5.5 billion. Kemper's captured CO_2 will be used for EOR in a Mississippi oil field.[52]

There are several other CO_2-emitting industrial facilities that capture and sequester CO_2 or use it in EOR. The Great Plains Synfuels Plant in North Dakota provides approximately 8700 tons per day of CO_2 for use in EOR at the Weyburn and Midale oil fields in Saskatchewan.[53] Great Plains Synfuels receives $20 per ton for its CO_2 and the project is expected to ultimately result in the storage of 20 million tons of CO_2.[54] The Sleipner gas processing facility in Norway had sequestered more than ten million tons of

46 Carnegie Mellon, Van Ness Feldman Attorneys at Law, Vermont Law School, & University of Minnesota. (2009, July). *Policy Brief: Comprehensive Regulation of Geologic Sequestration.* CCSReg Project. Available at: http://www.ccsreg.org/pdf/ComprehensiveReg_07202009.pdf

47 Refer to the CCSReg Project website at: http://www.ccsreg.org/billtable.php?component=Sequestration and http://www.ccsreg.org/billtable.php?component=Transportation.

48 US EPA. (2014, January 8). *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule,* pp. 1474–1475. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

49 Refer to the SaskPower website at: http://www.saskpowerccs.com/ccs-projects/boundary-dam-carbon-capture-project/carbon-capture-project/.

50 Massachusetts Institute of Technology. (2014, March). *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/boundary_dam.html

51 Folger, P. (2014, February). *Carbon Capture and Sequestration: Research, Development, and Demonstration at the US Department of Energy.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R42496.pdf

52 Massachusetts Institute of Technology. (2014, May). *Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/kemper.html

53 Massachusetts Institute of Technology. (2013, December). *Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/weyburn.html

54 Supra footnote 53.

CO_2 as of 2008.[55] Sleipner was designed specifically as a sequestration project in order to avoid paying Norway's carbon tax on CO_2 emissions. A second gas processing facility, In Salah in Algeria, injected about 3.8 million tons of CO_2 into a depleted gas reservoir for seven years before ceasing operations because of concerns about the integrity of the caprock.[56] More recently, an Archer Daniels Midland ethanol plant in Decatur, Illinois captured and sequestered 317,000 tons of CO_2 in its first year of operations.[57] The project is scheduled to continue through September 2015.[58]

In general, efforts in the United States to deploy carbon capture and/or storage are funded, at least in part, by the US Department of Energy (DOE). On the storage side, the DOE's Regional Carbon Sequestration Partnership supported seven regional partnerships pursuing a number of projects intended to ultimately sequester one million tons of CO_2 or more.[59] The Decatur, Illinois project discussed previously is one of these. And the Cranfield project in Mississippi had stored 4.7 million tons of mostly natural,[60] as opposed to anthropogenic, CO_2 by August 2013.[61]

A prominent piece of the DOE's investment in CCS research was the FutureGen project. Originally announced in 2003 and first conceived as an IGCC plant that would capture and sequester at least one million metric tons of CO_2 per year,[62] FutureGen was restructured in 2008 and then postponed because of rising costs.[63] In 2010, former Secretary of Energy Steven Chu announced a new version of the project, FutureGen 2.0, which would use $1 billion of American Recovery and Reinvestment Act money to retrofit an existing pulverized coal plant in Meredosia, Illinois with oxy-combustion capture and sequestration.[64] In February 2015, however, the DOE directed the suspension of FutureGen 2.0 project development activities because the project could not be completed prior to the expiration of American Recovery and Reinvestment Act funding in September 2015.[65]

4. GHG Emissions Reductions

There were more than 550 coal-fired power plants in the United States in 2012.[66] Some of those plants will retire before the proposed initial 111(d) compliance period begins in 2020. However, the majority are likely to still be operating and could be candidates for CCS.

55 Massachusetts Institute of Technology. (2014, January). *Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/sleipner.html

56 Massachusetts Institute of Technology. (2014, January). *In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/in_salah.html

57 Massachusetts Institute of Technology. (2014, May). *Decatur Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/decatur.html

58 Ibid.

59 Supra footnote 11.

60 Southeast Regional Carbon Sequestration Partnership. (2007). *Factsheet for Partnership Field Validation Test: SECARB Phase III Tuscaloosa Formation CO_2 Storage Project.* Available at: http://www.netl.doe.gov/publications/proceedings/07/rcsp/factsheets/3-SECARB_Large%20Scale%20Saline%20Formation%20Demo.pdf

61 Massachusetts Institute of Technology. (2013, December). *Cranfield Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/cranfield.html

62 Government Accountability Office. (2009, February). *Clean Coal: DOE's Decision to Restructure FutureGen Should Be Based on a Comprehensive Analysis of Costs, Benefits, and Risks.* GAO-09-248. Available at: http://www.gao.gov/new.items/d09248.pdf

63 Folger, P. (2014, February). *The FutureGen Carbon Capture and Sequestration Project: A Brief History and Issues for Congress.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R43028.pdf

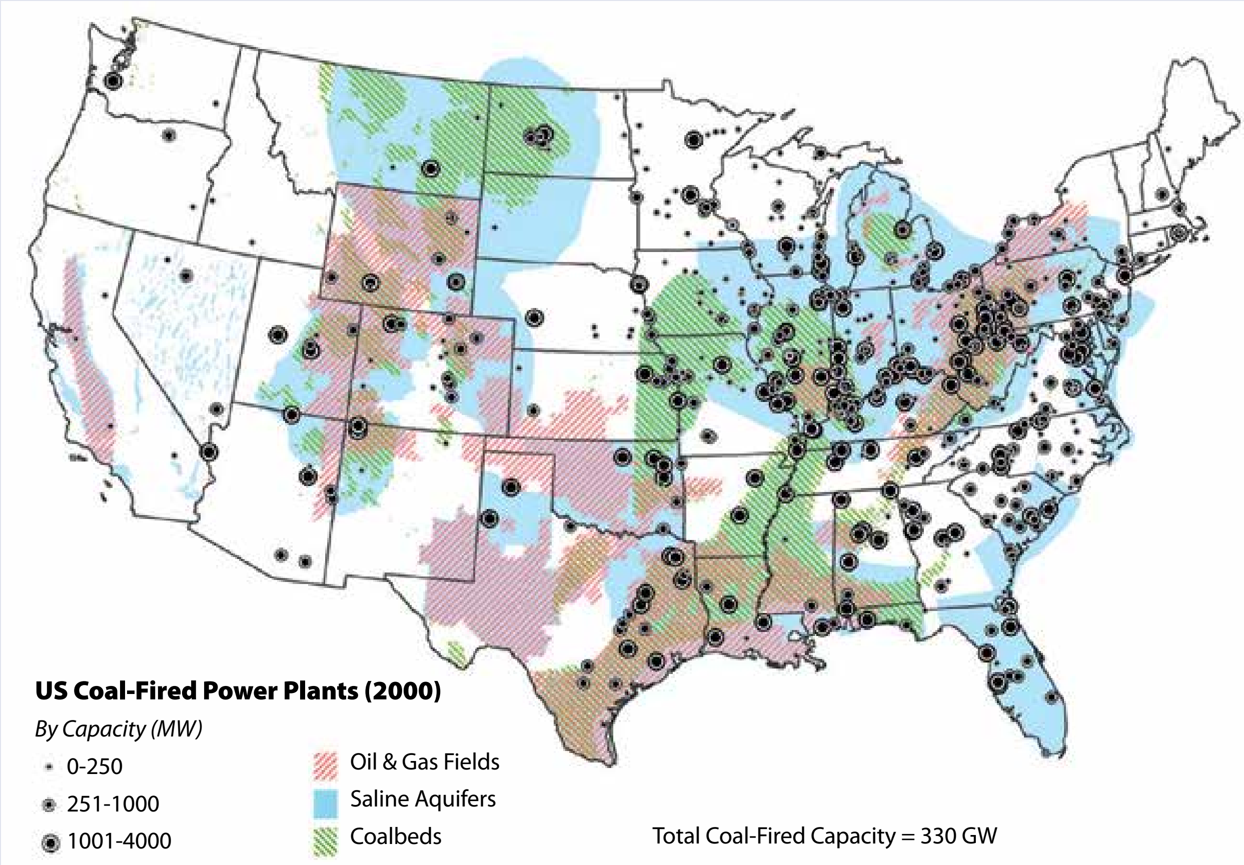
64 Ibid.

65 Daniels, S. (2015, February 3). *FutureGen 'Clean-Coal' Plant is Dead.* Crain's Chicago Business. Available at: http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead

66 Refer to the US Energy Information Administration website at: http://www.eia.gov/electricity/annual/html/epa_04_01.html.

Figure 7-10

Many Coal-Fired Power Plants Overlie Potential Storage Formations[67]



Should large-scale deployment of CCS occur, not all those facilities would be retrofitted, but on the basis of location alone, few can be ruled out as candidates. Figure 7-10 shows the extent to which coal-fired power plants overlie saline aquifers, hydrocarbon reservoirs, and coal seams. This synergy is part of the reason that CCS may have large potential. Note, however, that no pipeline network connecting power plants to potential CO_2 storage formations currently exists. That infrastructure would need to be built in conjunction with any CCS retrofits.

Table 7-1

Potential CO_2 Emissions Reductions per Year From CCS

CO_2 Emissions From Coal-Fired Power Plants in 2012[68] (million metric tons)	Potential Emissions Sequestered With 30% Capture (million metric tons)	Potential Emissions Sequestered With 60% Capture (million metric tons)	Potential Emissions Sequestered With 90% Capture (million metric tons)
1514	454	908	1363

Assuming all existing coal-fired power plants are retrofitted with CCS, the potential scale of sequestered emissions is estimated in Table 7-1.

Using the most recent emissions data from the year 2012, with 30 to 90 percent capture at all coal-fired power plants, a total of 454 to 1363 million metric tons of CO_2 could potentially be sequestered each year. Table 7-1 is akin to a simple technical potential estimate. It does not take into account the cost of sequestering this quantity of CO_2, nor the feasibility of doing so. And some subset of existing

67 Orr, F. (2009). CO_2 Capture and Storage: Are We Ready? *Energy & Environmental Science, 2,* pp. 449–458. Available at: http://pubs.rsc.org/en/Content/ArticleLanding/2009/EE/b822107n#!divAbstract

68 Refer to the US Energy Information Administration website at: http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11.

coal-fired power plants may simply be unable to retrofit because their sites cannot accommodate the footprint of a CCS system.

5. Co-Benefits

The primary co-benefit of CCS is that it would allow the United States to continue using a fuel (i.e., coal) that provides a large, although declining, share of the country's electricity even as we enter a carbon-constrained world.

There is relatively little information about CCS's other possible co-benefits such as employment and economic impacts. With regard to air emissions, applications of CCS at *new* pulverized coal plants would lower sulfur dioxide emissions as the proportion of carbon captured increases. However, nitrogen oxides, particulate matter, and mercury emissions would increase.[69] We would expect the same to be true of retrofit applications.

The full range of possible co-benefits associated with CCS is summarized in Table 7-2.

6. Costs and Cost-Effectiveness

The US Energy Information Administration (EIA) periodically produces estimates of the overnight capital costs of constructing new power plants with CCS as part of the modeling assumptions that are used in the *Annual Energy Outlook*. In the most recent data set, the EIA estimates that adding CCS to a typical, new, advanced pulverized-coal generating unit would increase the capital costs from $3246/kilowatt (kW) to $5227/kW. For an IGCC unit, the cost increases from $4400/kW to $6599/kW. And for an advanced natural-gas fired combined-cycle unit, the cost doubles from $1023/kW to $2095/kW.[70] The EIA also produces estimates of the levelized cost of energy for those plants. For an IGCC unit, the EIA estimates that CCS adds $31.5/MWh to the levelized cost of energy; for advanced natural-gas fired combined-cycle units, CCS increases costs by $26.9/MWh.[71]

Because of limited implementation experience, there is little information estimating the costs of retrofitting existing power plants with carbon capture. A 2014 presentation by the National Energy Technology Laboratory (NETL) predicted that retrofitting a pulverized coal plant with post-combustion capture would raise its cost of energy from $45 to $124 per MWh (2011$) and

Table 7-2

Types of Co-Benefits Potentially Associated With CCS

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	No
Sulfur Dioxide	Yes
Particulate Matter	No
Mercury	No
Other	No
Water Quantity and Quality Impacts	No
Coal Ash Ponds and Coal Combustion Residuals	No
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	No
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	No
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other:	

69 NETL. (2013, September). *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.* DOE/NETL-2011/1498. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

70 Refer to the EIA website at: http://www.eia.gov/forecasts/capitalcost/.

71 Refer to the EIA website at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

cost $72 per ton of CO_2 captured.[72] No further supporting documentation or details for these estimates appears to have been published.

A 2011 analysis published in *Energy Procedia* estimated that the revenue requirement of power plants retrofitted with post-combustion capture and using ammonia as the absorbent would vary between $117 and $148 per MWh.[73] The authors noted that there were limited data from which to develop their estimates and identified 11 key uncertainties that would influence the cost of capture, including the auxiliary steam loads, cooling equipment costs, and CO_2 compression.

In 2007, the Massachusetts Institute of Technology estimated that retrofitting an existing coal plant would cost $1600 per kW and reduce net plant output by at least 40 percent.[74] The authors of this report suggested that it may be more economical to simply rebuild coal plants with more efficient supercritical or ultra-supercritical boilers (the majority of existing plants are subcritical) so as to raise the efficiency of the plant.

Although it did not present any CCS cost estimates in its 111(d) proposed rule, the EPA concluded that "the costs of integrating a retrofit CCS system into an existing facility would be substantial. For example, some existing sources have a limited footprint and may not have the land available to add a CCS system. Moreover, there are a large number of existing fossil-fired EGUs. Accordingly, the overall costs of requiring CCS would be substantial and would affect the nationwide cost and supply of electricity on a national basis."[75]

There is also little information on the cost of oxy-combustion. NETL simply states that oxy-combustion systems are not "affordable at their current level of development" owing to problems with capital cost, parasitic energy demand, and operational challenges.[76] The only power plant proposed to use this technology, FutureGen 2.0, would have had a projected gross output of 168 MW and was originally estimated to cost $1.3 billion, but this estimate rose to $1.65 billion.[77] That project was effectively ended in February 2015 when the DOE suspended its federal funding.

NETL estimated the cost of transporting and storing CO_2 to be anywhere from approximately $10 to $22 per ton of CO_2, depending on factors like capture rate, plant capacity factor, and the total quantity of CO_2 sequestered.[78] However, the Intergovernmental Panel on Climate Change puts the cost of storage alone as high as $30 per ton of CO_2.[79]

7. Other Considerations

Any power plant, new or retrofitted, that captures CO_2 will consume significantly more water than it would otherwise. In water-constrained regions, this additional water consumption may pose a material obstacle to permitting a CCS project. Figure 7-11 shows NETL's theoretical estimates of water consumption at new power plants with and without carbon capture.

At pulverized coal plants, water consumption would likely double. Cooling water duties increase as a result of both

72 Gerdes, K. (2014, January). *NETL Studies on the Economic Feasibility of CO_2 Capture Retrofits for the US Power Plant Fleet.* US Department of Energy. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-Retrofits-Overview-2014-01-09-rev2.pdf

73 Versteeg, P., & Rubin, E. (2011). Technical and Economic Assessment of Ammonia-Based Post-Combustion CO_2 Capture. *Energy Procedia 4,* pp 1957–1964. Available at: http://www.sciencedirect.com/science/article/pii/S1876610211002736

74 Massachusetts Institute of Technology. (2007). *The Future of Coal: Options for a Carbon-Constrained World.* Available at: http://web.mit.edu/coal/The_Future_of_Coal.pdf

75 US EPA. (2014, June 18). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule,* p. 34876. Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

76 Refer to the NETL website at: http://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion.

77 Folger, P. (2013, April). *FutureGen: A Brief History and Issues for Congress.* Congressional Research Service Reports. Available at: http://op.bna.com/env.nsf/id/avio-96nmz2/$File/CRS%20report%20FutureGen.pdf

78 Grant, T., Morgan, D., & Gerdes, K. (2013, March). *Carbon Dioxide Transport and Storage Costs in NETL Studies.* NETL. DOE/NETL-2013/1614. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

79 Supra footnote 23.

capture and compression. For example, in amine-based post-combustion capture systems, the capture reaction is exothermic, which necessitates cooling to allow the reaction to proceed as efficiently as possible. The process of compressing CO_2 nearly two orders of magnitude from 23 PSI to 2200 PSI creates enough heat to require additional cooling water as well.[81]

The increase in water consumption is just one of several factors contributing to an increase in auxiliary (a.k.a. "parasitic") power demand. Regenerating the solvent used to capture the CO_2 normally requires part of the plant's steam output and thereby reduces the net power output. Figure 7-12 shows the difference in plant efficiency at new pulverized coal plants with and without capture. Similar data for retrofits of existing power plants are not available owing to the lack of full-scale retrofit projects.

The decline in net plant efficiency can be thought of as a proxy for the decline in plant output, because a decrease in efficiency means that the electric output per unit of energy input has decreased. Retrofits of existing plants would be expected to result in at least the degree of change in efficiency shown for new plants in Figure 7-12 (i.e., approximately a ten-percentage-point decrease in efficiency). The *Future of Coal* study published by the Massachusetts Institute of Technology, citing data from Alstom Power, concluded that retrofitting a subcritical pulverized coal plant would reduce efficiency by about 14 percentage points, which translates to a 41-percent relative reduction in net output.[83] The Global CCS Institute

Figure 7-11

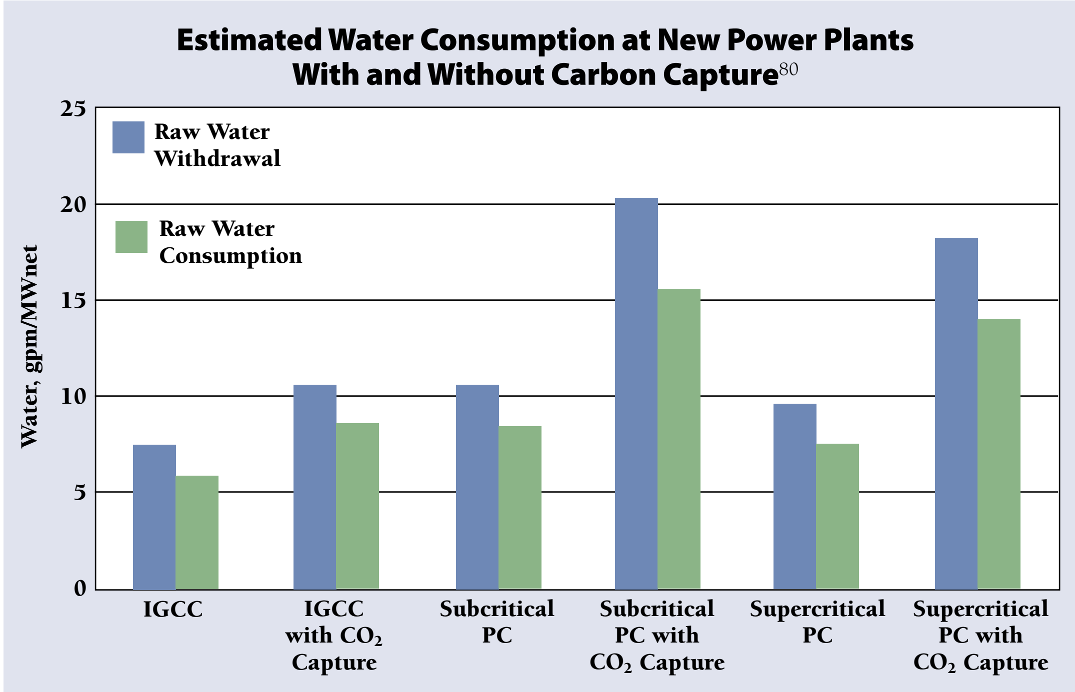
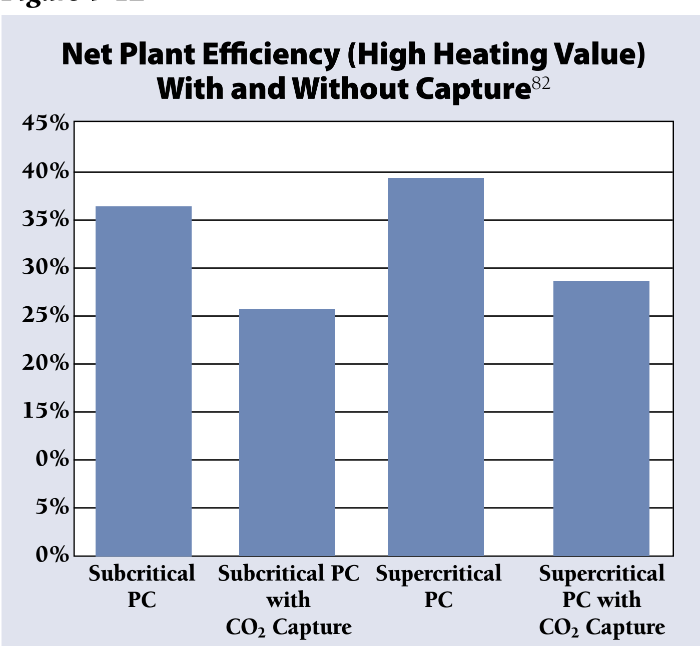


Figure 7-12



80 Based on data from: NETL. (2013, September). *Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity.* US Department of Energy. DOE/NETL-2010/1397. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf

81 NETL. (2013, September). *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.* US Department of Energy. DOE/NETL-2011/1498. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

82 Supra footnote 80.

83 Supra footnote 74.

offers a somewhat more optimistic assessment, estimating a parasitic load of 20 to 30 percent for post-combustion CO_2 capture and compression technologies, with net plant efficiency dropping from 38 to 27 percent.[84] The practical implication for existing plant retrofits is that this reduction in power output may have to be made up by other sources of power. This indirect cost and the possible CO_2 emissions from these other sources of power are rarely accounted for in estimates of CCS costs and benefits.

If CCS is to be used as an essential strategy for complying with mandatory CO_2 emissions regulations, some issues surrounding the coordination of ordinary power plant operations with CO_2 compression, transportation, and storage operations are likely to arise and will need to be resolved. If, for instance, the pipeline is unavailable for some reason, the plant operator would have to decide whether to vent the CO_2, shut down the plant, or find some way to store the CO_2. Some research has been done into storing CO_2-rich solvent in such situations.[85] These strategies could also be used during times of peak demand when it would be preferable to have the plant's full output.

Although many reports, including this one, may seem to blur the line, it should be emphasized that there is a difference between CO_2-EOR and carbon storage – one seeks to improve oil production and the other to sequester CO_2. A CO_2-EOR project can eventually transition to a carbon storage project,[86] but in the interim, some but not all of the CO_2 injected for EOR will be sequestered. Therefore, tons of carbon captured for the purpose of CO_2-EOR do not yield the same tons of CO_2 sequestered.

Because CO_2-EOR increases the production of oil, there may also be implications for the carbon benefit attributed to EOR-focused CCS projects. The ultimate fate of that recovered oil is combustion in some form, which in turn creates its own CO_2 emissions. Therefore, from a lifecycle perspective, the total sequestration benefit of CO_2-EOR is certainly less than the total mass of CO_2 sequestered. Indeed, a 2009 analysis of five CO_2-EOR sites found that all were net *positive* emitters of CO_2 after accounting for the combustion of the recovered oil.[87] Regulation of GHG emissions either across the entire economy or from a lifecycle perspective would account for this impact.

Economy-wide regulation of GHG could also have negative implications for the economics of CO_2-EOR projects. Although operators of EOR projects currently pay for CO_2, in a world with a price on each ton of CO_2 emitted regardless of its source, it is not clear that the EOR market would continue to *pay* for CO_2. It could be that CO_2-emitting facilities would have to compensate EOR operators for taking their CO_2 instead of receiving revenue for it. Such a shift in the EOR market could dramatically change the economics of capture projects relying on an EOR revenue stream.

Public acceptance of CCS may also play a role in its success or failure. For example, to the extent that the public perceives hydraulic fracturing (or "fracking") for oil and natural gas as the same or similar to CCS because it involves underground fluid injection, there could be a strong, negative reaction to CCS projects.[88]

84 Global CCS Institute. (2012, January). *CO_2 Capture Technologies: Post Combustion Capture (PCC)*. Available at: http://www.globalccsinstitute.com/publications/co2-capture-technologies-post-combustion-capture-pcc

85 Chalmers, H., Lucquiaud, M., Gibbins, J., & Leach, M. (2009). Flexible Operation of Coal Fired Power Plants With Postcombustion Capture of Carbon Dioxide. *Journal of Environmental Engineering, 135,* Special Issue: Recent Developments in CO_2 Emission Control Technology, 449–458. Available at: http://ascelibrary.org/doi/abs/10.1061/%28ASCE%29EE.1943-7870.0000007

86 Whittaker, S. (2010, October). *IEA GHG Weyburn-Midale CO_2 Storage & Monitoring Project*. Regional Carbon Sequestration Partnerships Annual Review. Available at: http://www.netl.doe.gov/publications/proceedings/10/rcsp/presentations/Tues%20am/Karen%20Cohen/Whittaker.%20WMP_Regional%20Partnership.pdf

87 Jaramillo, P., Griffin, W., & McCoy, S. (2009). Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System. *Environmental Science & Technology, 43,* pp. 8027–8032. Available at: http://www.ncbi.nlm.nih.gov/pubmed/19924918

88 Supra footnote 51.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CCS.

- Metz, B., Davidson, O., de Coninck, H., Loos, M., & Meyer, L., eds. (2005). *Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge, United Kingdom: Cambridge University Press. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf
- Folger, P. (2013, November). *Carbon Capture: A Technology Assessment.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R41325.pdf
- Parfomak, P. (2008, July). *Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/RL34601.pdf

9. Summary

CCS offers the potential to prevent the emissions of millions of tons of CO_2 from fossil-fuel fired power plants into the atmosphere. The extent to which that potential is leveraged will be determined by our ability to overcome the technical and economic hurdles that confront this technology. Carbon capture is costly and has significant auxiliary power demands. Carbon storage may be hindered by the absence of a robust legal framework under which it can be implemented and requires further research into its functionality. It remains to be seen whether federal action – including the New Source Performance Standards for GHG emissions from utility boilers and IGCC plants and the DOE's research and development efforts in CCS – will spur sufficient interest and investment to make it a commercial technology.

Chapter 8. Retire Aging Power Plants

1. Profile

Retiring aging fossil-fired electric generating units (EGUs) can produce significant reductions in greenhouse gas (GHG) emissions. This is particularly true when the EGUs in question are existing coal-fired units, because their carbon dioxide (CO_2) emissions are typically double those of natural gas combined-cycle EGUs. Most of the EGUs currently slated for retirement are coal-fired units, resulting from greater fuel price competition with natural gas, higher operating costs, and new environmental regulations such as the US Environmental Protection Agency's (EPA) recent Mercury and Air Toxics Standards (MATS). The EPA has identified 233 coal-fired, non-cogeneration EGUs which, based on recent announcements, have retired or are expected to do so before 2016.[1]

Although retiring aging coal-fired EGUs is becoming more and more prevalent, these decisions remain a sensitive topic. Despite the likely environmental benefits, retiring an aging EGU has the potential to produce profound economic consequences for utility ratepayers, companies, and the community where the unit is located. Paying for a unit to retire can be expensive and disruptive. However, when weighed against various policy alternatives, retiring an aging EGU may be a lower-cost solution to the challenge of emissions reductions and worthy of inclusion in a state's Clean Air Act compliance plans.

There are numerous factors that can affect a plant owner's or regulator's decision to continue operating an aging EGU or to retire it. These include forward-looking market factors and environmental regulatory requirements. The ability to recover past plant-related investments will also heavily influence the decision. States that consider EGU retirement as a compliance option will have to consider these issues, and the varying degrees to which these factors support such a decision. Consideration of these same issues has led many plant owners and regulators to require aging EGUs to be repowered (to utilize a lower-emitting fuel) instead of retired – a policy option reviewed in detail in Chapter 9. Along these lines, some observers have recommended (but not yet implemented) the idea that retirement deliberations be institutionalized through the adoption of a "birthday provision" whereby EGUs would automatically become subject to new source emissions standards upon expiration of their originally defined useful lifetime.

Although the EPA's Clean Power Plan proposal of June 2014 nowhere mandates EGU retirements, given the flexibility that the proposal would provide states, this option — with its related benefits and challenges — constitutes a potential compliance pathway worthy of state consideration.

2. Regulatory Backdrop

Most EGU retirement decisions begin with a decision by the owner of the EGU that it makes sense to retire the unit. There are also limited examples of decisions that are initiated by other decision-makers and imposed on EGU owners.

The market and regulatory context in which an EGU operates provides an additional backdrop and regulatory context for retirement decisions. In most cases, the owner of the EGU will need additional approvals before it can actually retire the unit. To understand these approvals it is helpful to review some of the terminology used to describe

1 The EPA reports that its "research found 233 coal-fired, non-cogeneration EGUs that have announced they will retire before 2016." US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. p. 235, note 29 citing to Integrated Planning Model documentation includes a list of the announced retirements. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf. See Table 4-36 of Integrated Planning Model Documentation: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_4.pdf

EGU ownership and energy markets.

EGUs can be owned by "vertically integrated" utilities that own electric generation assets and an electric distribution system, and sell energy to retail customers within their retail monopoly jurisdiction. Large EGUs may be jointly owned by more than one party. Vertically integrated utilities can be investor-owned, publicly owned, or member-owned cooperatives. States vary in terms of whether and how each type of utility is regulated by the state public utility commission (PUC), with the common thread being that investor-owned utilities are regulated by PUCs everywhere. EGUs can also be owned by non-utility "independent power producers," also known as "merchant generators."

In some parts of the country, the electric power sector has been "restructured." Utilities in those areas were required to divest their ownership of EGUs. Although distribution utilities continue to exist in those areas, they only have a monopoly with respect to the distribution system. All EGUs in those areas are owned by merchants and the wholesale sale of electricity is a competitive market.

Today there are a variety of energy market structures in place around the United States. "Traditionally regulated" markets persist in many jurisdictions (principally in the West and the South). In those areas, most EGUs are owned and controlled by vertically integrated utilities, but some merchant generators own EGUs and sell energy to utilities through bilateral contracts. EGU dispatch decisions are made in those areas by the utility based on the needs of its customers. In other areas, competitive wholesale electricity markets have been created, in most cases spanning across state lines. Within those competitive wholesale markets, EGUs may be owned by vertically integrated utilities or by merchant generators, but decisions about which EGUs operate (and at what level of output) are made by an independent system operator (ISO) or regional transmission organization (RTO) based on system-wide customer needs and competitive bids made by EGU owners.

Returning to the issue of EGU retirements, in different jurisdictions retirements occur as a result of unit owner decisions, decisions from ISOs with organized wholesale markets that permit units to be "de-listed," and rulings from state regulatory commissions in "abandonment" proposals, planning dockets, or special accounting or rate-treatment processes.

Unit Owner Decisions

EGU owners make decisions to retire plants for various economic and other reasons explained in greater detail later in this chapter. In restructured jurisdictions, EGUs are owned by merchants, and retirement and cost considerations are not likely to be subject to PUC review. However, in jurisdictions with organized wholesale markets, those EGU owners' retirement decisions must be reviewed by the ISO or RTO as explained below. In traditionally regulated jurisdictions, EGU owners' retirement decisions must be reviewed and approved by state regulatory commissions except in cases in which the PUC has no regulatory authority (as is sometimes the case for publicly owned utilities and cooperatives and normally the case for merchant generators). These processes are described in more detail below.

ISO/RTO Decisions

In organized wholesale markets like the PJM Interconnection (PJM) or Midcontinent Independent System Operator RTOs, electric generation is made available through resource auctions and the establishment of a dispatch order for EGUs based on economic merit (see Chapter 21 for a more comprehensive discussion of dispatch order). For example, in the New England ISO's energy markets,[2] in order to participate an EGU owner needs to submit a bid reflecting the amount of energy that the generator can provide and the price, and that bid must clear through the auction. If the bid is successful (i.e., the unit owner has a position and a price), that EGU must deliver generation for the specific time and

2 Power plants that participate in organized markets are paid for both the energy they produce and for the generation capacity that they agree to provide. Electric energy is produced and sold daily at wholesale and then resold to end-use consumers. Capacity is typically sold over longer time periods in an attempt to ensure that generation resources will be available in the future and that there is enough time to build them. In PJM, for example, there is an annual auction for power delivery three years in the future. There are also other smaller capacity markets where, within that three-year time frame, power can be sold to ensure that precisely the right amount will be available when it is needed. For further discussion of capacity markets, see Chapter 19. For a more complete discussion of this topic, also see, e.g.: James, A. (2013, June 17). *Explainer: How Capacity Markets Work.* MidWest Energy News. Available at: http://www.midwestenergynews.com/2013/06/17/explainer-how-capacity-markets-work/

in the amount of capacity it bid. If it fails to do so, it could face a penalty, and would certainly forego any revenue for the electricity it failed to deliver. Additional details regarding capacity markets and dispatch are also provided in Chapters 19 and 21.

In this context, retirement involves removing an EGU from current or future auctions, a process called "de-listing." In the New England ISO's forward capacity market, existing resources are able to leave the market by submitting a "de-list" bid.[3] All de-list bids are subject to a reliability review by the ISO. If the ISO concludes that the unit submitting the de-list bid is needed for reliability purposes, the bid is rejected and the resource is retained.[4] Other RTOs and ISOs possess similar ability to deny EGU retirements that would jeopardize system reliability.[5]

Decisions in Traditionally Regulated Markets

Retirement of EGUs works differently in traditionally regulated or vertically integrated markets; there, EGU owners are relatively free to retire a unit if they wish. Owners make such decisions subject to reliability demands and to any additional constraints that might be included in a generator's permission to operate, that is, a "certificate of public convenience and necessity" or "certificate of public good" granted by a state commission where the generator is located.

For example, Public Service Company of Colorado, as part of its decision-making under Colorado's "Clean Air – Clean Jobs Act,"[6] relied on its own dispatch models and reviewed options across its system to "take action" (i.e., to retire, control, or fuel-switch a unit to natural gas). Companies in traditionally regulated markets have responsibility for capacity and are required to demonstrate that they can meet this responsibility, but generally speaking there is no affirmative obligation to offer any particular EGU for service.

Decisions by State Regulatory Commissions

When an EGU retirement proposal comes before state regulatory commissions, it is likely to do so in one of the following contexts: "abandonment" proposals or relinquishment of certificates of public convenience and necessity; planning dockets; or special accounting or rate-treatment processes. The value of being able to review retirement proposals is that it provides an opportunity to require a utility to produce a thorough analysis of the potential costs of the proposal and reasonable alternatives, and to subject that analysis to public scrutiny through an administrative proceeding. These processes are briefly described below.

Relinquishment of Certificate of Public Convenience and Necessity

EGUs need regulatory permission to go into service, and they are typically issued a certificate to do so by state utility commissions. These certifications are granted after a commission's public review of the suitability of a proposal, including financial, legal, engineering, and other relevant considerations.

Companies need permission to take EGUs out of service as well, as illustrated below in Vermont's statutory requirements:

> *A company subject to the general supervision of the public service board … may not abandon or curtail any service subject to the jurisdiction of the board or abandon all or any part of its facilities if it would in doing so effect the abandonment, curtailment or impairment of the service, without first obtaining approval of the public service board, after notice and opportunity for hearing, and upon finding by the board that the abandonment or curtailment is consistent with the public interest….*[7]

As the statute indicates, this regulatory review is intended to examine whether or not abandoning an EGU will affect the company's service, specifically calling out

3 ISO New England, Inc. (2012, May 15). *Overview of New England's Wholesale Electricity Markets and Market Oversight*. Internal Market Monitor, pp. 7–8. Available at: http://iso-ne.com/pubs/spcl_rpts/2012/markets_overview_final_051512.pdf

4 See ISO New England Inc. 5th Rev. Sheet No. 7308, FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design Tariff at Section III.13.2.5.2.5: "The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules."

5 In each ISO market, there are also rules (tariffs) that specify how an EGU owner whose de-listing request has been denied will be "made whole" through wholesale market compensation for costs that exceed revenues.

6 A process that was ultimately reviewed and approved by the state utility commission and environmental agency.

7 30 V.S.A. § 231(b). *Certificate of Public Good; Abandonment of Service; Hearing.*

"impairment of service" (i.e., reliability) as a criterion. In an abandonment proceeding, a utility has to demonstrate why its proposal to retire an EGU is in the public interest. It is also an opportunity for the utility commission to provide the public its reasons for granting or denying its approval.

Planning

Utility planning, also referred to as integrated resource planning (IRP), is another context in which a state might review a proposal to retire an EGU.[8] An IRP docket is a public process designed to look broadly at a utility's needs over a certain time period, and to identify the least-cost means of meeting those needs. More specifically, an IRP investigation is a review of various supply- and demand-side options, potential utility plans, and a schedule to monitor and revisit plans as necessary. PacifiCorp, for example, describes its IRP as a:

> *Comprehensive decision support tool and road map for meeting the company's objective of providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business.*[9]

The value in having this structured and comprehensive look forward lies in being able to identify a resource mix before capital is committed to expenditures. This is the case in a traditionally regulated environment in which a utility will seek approval of expenditures. It is also the case in restructured states, where some decisions – transmission expansions, for example – can be shaped or targeted to reflect least-cost, least-risk options.

In the context of EGU retirements, it is also valuable to identify alternatives that avoid raising electric system reliability problems.[10] An IRP's typical "least-cost" criterion implies "the lowest total cost over the planning horizon, given the risks faced" – including reliability. The best resource mix is one that "remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution."[11] Planning for EGU retirement is thus an extensive examination of related costs, and costs associated with alternatives. Additional details regarding IRP are provided in Chapter 22.

Tariff Riders and Preapproval

Some state laws provide for the recovery of costs associated with environmental compliance. Given the flexibility granted states by the EPA's proposed Clean Power Plan, an argument could be made that costs related to EGU retirement fit in the category of recoverable costs.

An adjustment clause (also sometimes referred to as a "cost tracker" or "tariff rider") is a separate surcharge (or sur-credit) to incorporate specific costs in rates, independent of overall utility costs and rates established in a general rate case.[12] Utilities in some jurisdictions also enjoy preapproval of expenditures related to environmental compliance.[13] In these cases, utility regulators generally review the proposed plan and the associated budget, and allow cost recovery (barring imprudence in implementing an approved plan[14]). Preapproval is not an uncommon practice and, once obtained, makes cost recovery by the

8 See Chapter 22 for a comprehensive discussion of IRP.

9 PacifiCorp. Integrated Resource Plan website, Overview. Available at: http://www.pacificorp.com/es/irp.html. See also: Lazar, J. (2011, March). *Electricity Regulation in the US: A Guide,* p. 73. Available at: http://www.raponline.org/document/download/id/645, and Farnsworth, D. (2011). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance,* pp. 20–38, for a more detailed discussion of integrated planning. Available at: www.raponline.org/document/download/id/919

10 US EPA. (2014, June). *Technical Support Document (TSD): Resource Adequacy and Reliability Analysis.* Office of Air and Radiation. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf. The EPA defines the term "resource adequacy" to mean "the provision of adequate generating resources to meet projected load and generating reserve requirements." It defines "reliability" as ensuring the "ability to deliver the resources to the loads, such that the overall power grid remains stable." Reliability Standards for the Bulk Electric Systems of North America, updated December 16, 2014. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

11 Lazar, at supra footnote 9.

12 For a general discussion of adjustment mechanisms, see: Ibid.

13 See discussion of Alabama Power below at footnotes 87–88 and accompanying text.

14 An inquiry into the "prudence" of a decision might focus on such things as failure to consider factors known to management in the original proposal, failure to effectively manage a retrofit process, or failure to reconsider the project as additional cost information becomes available.

utility highly likely.[15] Under Ohio law, for example, an automatic recovery rider allows for utilities to recover the costs of environmental compliance, including "the cost of emission allowances; and the cost of federally mandated carbon or energy taxes…" and a "reasonable allowance for construction work in progress … for an environmental expenditure for any electric generating facility of the electric distribution utility."[16] Regulators need to assess the circumstances and financial impacts of EGU retirements claimed as recoverable costs, especially where preapproval provisions exist.

State 111(d) Compliance Plans

The EPA's Clean Power Plan, proposed in June 2014, would impose a requirement on states to develop a plan for reducing the average CO_2 emissions rate of affected EGUs to specified levels (or "goals") by 2030. The EPA would not require states to include EGU retirements in their plans, but states would have the option to do so. If an EGU has a higher-than-average emissions rate, and the output of the EGU can be replaced with the output from an EGU not affected by the rule or by an affected EGU that has a lower CO_2 emissions rate, the average emissions rate of affected EGUs will decline and the state will be closer to compliance with its emissions goal. This fact, combined with the fact that it is relatively easy to administer and enforce a retirement decision (compared, for example, to other emissions reduction options), may make EGU retirements an option of interest to state air pollution regulators even in the face of the economic complexities that factor into these decisions.

3. State and Local Implementation Experiences

As noted previously, various administrative approaches provide utility regulators with frameworks to analyze potential costs and other relevant factors (such as reliability implications) associated with retirement proposals. The examples below – reflecting both restructured and traditionally regulated states – show that the exact process states use to analyze proposals may be less important than the willingness to take an integrated approach and thoroughly consider alternatives.

In 2011 the state of Colorado, a traditionally regulated state, used a process similar to IRP in implementing 2010 legislation that proposed, among other things, EGU retirements. The "Clean Air – Clean Jobs Act" (the Act) passed in April 2010 anticipated new EPA regulations for criteria air pollutants (nitrogen oxide [NO_X], sulfur dioxide [SO_2], and particulates), mercury, and CO_2.[17] It required:

> *[b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/Colorado Electric Utility Company LP … to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units.*[18]

The two Colorado utilities developed these required plans and gained the approval of the PUC and state air regulators on an extraordinarily rapid schedule. Their approved plans were then included in a state implementation plan (SIP) submitted by the state to the EPA. As a result, two coal-fired power units totaling more than 210 megawatts (MW) have been retired and repowered, and three additional units are expected to be retired and repowered by 2017. Formal IRP implementation is typically an ongoing, multiyear process; this effort, from signed legislation to EPA approval of

15 Although some states allow for preapproval as a matter of law or administrative practice, others insist that decision-making is a management responsibility and will only review the actions of management when an investment is completed and goes into service. Utility regulators reach their own conclusion on this issue, guided by state law and regulatory precedent.

16 Ohio Revised Code, Section 4928.143(B) (2) (a) and (b).

17 In addition to anticipating new EPA regulations for criteria air pollutants including CO_2, it requires a utility to (1) consult with the Colorado Department of Public Health and Environment on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (2) submit a coordinated multipollutant plan to the state PUC.

18 Memorandum from the Office of Legislative Legal Services to Legislative Counsel, March 16, 2011, re: H.B. 10-1365 and Regional Haze State Implementation Plan. Available at: http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf

Colorado's SIP changes, took approximately 30 months.[19]

It is often the case that a proposal to retire a power plant can itself change over the course of the proposal's review, as was the case with Nevada's Mohave Generating Station and Oregon's Boardman Plant. In some cases, the proposal to close can be amended and become a proposal to repower.

In 1999, the owners[20] of the Mohave Generating Station – a two-unit, 1580-MW coal-fired power plant built between 1967 and 1971 – executed a consent decree to either install SO_2 controls or close the plant by 2005.[21] In 2003, Southern California Edison approached the California PUC for approval of preliminary engineering costs for a retrofit.[22] After an extended hearing, the California PUC ordered a comprehensive review of the future of the Mohave project.[23] The Mohave Alternatives and Complements Study was completed in 2005. It examined alternatives to a retrofit of Mohave, found a wide variety of cost-effective options, and at the conclusion of the study, the Mohave plant was closed permanently on December 31, 2005.[24]

Oregon's 550-MW coal-fired Boardman plant was originally expected to operate until 2040. However, to comply with state and federal environmental regulations, in 2010 Boardman was required to install approximately $500 million of pollution control equipment by 2017. In early 2010, owner Portland General Electric (PGE) announced that it was considering an alternative plan for Boardman that would retire the plant in 2020. PGE asked regulators to allow it to make a $45 million investment by 2011 to partially clean up Boardman's emissions of mercury and NO_X, and then operate the plant until 2020.[25] In June 2010, Oregon's Environmental Quality Commission rejected PGE's proposal to close Boardman by 2020, stating that Oregon's Environmental Quality Commission did not oppose early shutdown of the plant, but only wanted to do so using the best options possible.[26] PGE proceeded to look at other ways to close the plant by 2020, including alternative levels of investment in controls and different closure dates. The company concluded that earlier closure than 2020 was not an option because that time was needed to develop alternatives for the power produced. Later in 2010, PGE filed its Integrated Resource Plan with the Oregon PUC, stating that the 2020 shutdown was its preferred option.[27] On the basis of its IRP analysis, PGE ultimately proposed termination of coal use at Boardman at the earliest date that the utility felt resulted in adequate reliability for its customers: 2020. After reviewing various alternatives, the Oregon PUC acknowledged this approach in its order on

19 The Act was signed into law in April 2010, a Commission docket was opened in May, and a final order was issued in December. In January 2011 the Colorado Department of Public Health and Environment adopted changes and the EPA approved the new Colorado SIP in September the following year. NARUC Climate Policy Webinar 3: State Case Studies. (2010, December 17). *Dispatches from the Front: The Colorado Clean Air-Clean Jobs Act.* Ron Binz, Chairman, Colorado Public Utilities Commission. Available at: http://www.naruc.org/Publications/Binz%20TFCP%20Presentation%20121710.pdf; NARUC Task Force on Climate Policy Webinar. (2011, March 11). *Coal Fleet Resource Planning: How States Can Analyze their Generation Fleet.* Colorado Case Study. Karen T. Hyde, Vice President, Rates & Regulatory Affairs, & Jim Hill, Director, Resource Planning and Bidding; Xcel Energy. Available at: http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=3

20 Southern California Edison was the majority owner (56 percent) of the plant. The Los Angeles Department of Water and Power (10 percent), Nevada Power Company (14 percent), and Salt River Project (20 percent) were the other owners.

21 Grand Canyon Trust, the Sierra Club, and National Parks Conservation Association sued the owners of Mohave because of haze over the Grand Canyon and other air pollution that was caused by the plant.

22 Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12016 Report Prepared for Southern California Edison SL-008587. (2006, February).

23 The California Public Utilities Commission ordered Southern California Edison to perform for them a study of alternatives for replacement or complement of its share of the Mohave Generating Station under Decision 04-12-016, issued on December 4, 2004.

24 Edwards, J. (2009, June 6). Laughlin Coal-Fired Power Plant Going Away. *Las Vegas Review-Journal*. Available at: http://www.reviewjournal.com/business/laughlin-coal-fired-power-plant-going-away

25 PGE was also considering using biomass to continue operating the plant after ending its use of coal.

26 Sickinger, T. (2010, June 28). DEQ Proposes New Options for Shutdown of PGE Coal Plant. *The Oregonian.*

27 During the pendency of the IRP process, the plant owners made additional investments that the Oregon PUC considered in its final decision.

PGE's IRP.

In jurisdictions that have restructured their utility sector, generation is considered a competitive service that is no longer subject to regulatory review or treatment. When Ohio restructured, for example, generators were given a choice to continue to be traditionally regulated by the PUC or to participate in a largely deregulated wholesale market. In 2010, Ohio Power sought approval for a rate adder in order to recover an unamortized plant balance of $58.7 million on its retiring 450-MW Sporn Unit 5, under the same statute that provided an automatic recovery rider for traditionally regulated facilities.[28] The Sporn Plant, however, had chosen to operate in the deregulated market, so the PUC denied its request for cost recovery for closure-related costs.

In many cases, EGU retirements are tied to approval of proposals to convert and repower them with another fuel.[29] Indianapolis Power & Light Company (IPL), for example, conducted an integrated analysis ahead of its proposal to the Indiana Utility Regulatory Commission to repower Harding Street Generation Station Unit 7 from coal to natural gas as part of the company's "overall wastewater compliance plan for its power plants."[30] The Commission had already approved IPL's proposal to convert Harding Street Units 5 and 6 from coal to natural gas. Unit 7's conversion would conclude the closing of all of IPL's coal units at Harding Street by 2016, a move that the company says, "would reduce IPL's dependence on coal from 79 percent in 2007 to 44 percent in 2017…."[31] This plan was motivated not only by IPL's need to comply with Clean Water Act requirements; these closures will enable IPL to close Harding Street Generation Station's coal pile and ash ponds, which are subject to Resource Conservation and Recovery Act (RCRA) solid waste rules.

4. GHG Emissions Reductions

EGU retirements that occur in response to GHG regulations have the potential to avoid significant amounts of GHG emissions. The retirement of coal, oil, or inefficient natural gas capacity will not only reduce GHG emissions, but also emissions of other regulated air pollutants, depending on the fuels burned at a retiring EGU.

CO_2, methane, and nitrous oxide emissions are all produced during coal combustion; nearly all of the fuel carbon (99 percent) in coal is converted to CO_2 during the combustion process.[32] This conversion is relatively independent of firing configuration.[33] Consequently, the level of avoided emissions available from a coal plant retirement will vary only slightly, depending on the operating characteristics of each unit, but more so based on the type of coal normally used at the plant. CO_2 emissions for coal are linked to carbon content, which varies between the classes of bituminous and subbituminous coals. As a consequence, there is a significant range in emissions factors within and between ranks of coal (Table 8-1).

Table 8-1

Average Input Emissions Factors of Coal[34]

Coal Type	Input Emissions Factor (lb CO_2/MMBTU)
Coal – Anthracite	227
Petroleum Coke	225
Coal – Lignite	212 to 221
Coal – Subbituminous	207 to 214
Coal – Bituminous	201 to 212

28 In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider, Case No. 10-1454-EL-RDR, Finding and Order at 19. (2012, January 11). Ohio Revised Code, Section 4928.143(B) (2) (a) and (b).

29 Repowering of existing EGUs is examined in Chapter 9.

30 IPL Power. (2014, August 15) IPL plans to stop burning coal at Harding Street Generation Station in 2016; Utility to seek approval to switch power generation from coal to natural gas. [Press release]. Available at: http://www.indianadg.net/ipl-announces-plans-at-harding-street-plant-to-switch-from-coal-to-natural-gas-in-2016/

31 Ibid.

32 AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, 1.1 Bituminous And Subbituminous Coal Combustion. Available at: http://www.epa.gov/ttn/chief/ap42/ch01/index.html

33 Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced.

34 Based on: US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units*. Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf

The majority of the fuel carbon not converted to CO_2 is entrained in bottom ash. Furthermore, carbon content also varies within each class of coal based on the geographical location of the mine. Methane emissions also vary with the type of coal being fired and the firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers.

Several utilities and operators of coal-fired power plants have already announced retirements. In late 2013, the Tennessee Valley Authority announced the retirement of eight coal-fired units totaling 3000 MW of capacity at three different plant sites.[35] These eight units include:

- All five coal-fired units in its Colbert, Alabama plant location, representing CO_2 emissions of 6.5 million tons in 2010;
- Unit 8 at Widow's Creek, Alabama, with 2010 CO_2 emissions of 3.3 million tons; and
- The smaller two of three units at Paradise, Kentucky with combined 2010 CO_2 emissions of 8.9 million tons.[36]

South Carolina Electric and Gas announced the closure of its 295-MW unit at Canadys station in November 2013,[37] completing the retirements of all units at this plant. The other two units at Canadys were closed by South Carolina Electric and Gas in 2012. In 2010, combined CO_2 emissions from these three units totaled 14 million tons.

Coal plant retirements have also been announced in restructured electricity markets. Energy Capital Partners, operators of the Brayton Point plant in Massachusetts, announced plans to close Units 1–3 of this plant when its supply agreements with ISO New England expire in May 2016.[38] In 2010, CO_2 emissions from Units 1–3 were 6.3 million tons.

SourceWatch, a project of the Center for Media and Democracy, has prepared an assessment of expected coal EGU retirements by size and year, starting with 2009 as the first year.[39] The list of planned retirements is constantly changing, which means that any assessment of the total capacity of expected retirements soon becomes outdated. For example, the Government Accountability Office (GAO) estimated in August 2014 that more than 42 gigawatts (GW) of coal capacity had either been retired since 2012 or was planned for retirement by 2025. This estimate in 2014 exceeded the high end of the range of expected retirements cited by GAO in a similar 2012 report.[40]

As for the aggregated impact of EGU retirements on CO_2 emissions, it must first be understood that EGUs vary in their output and their emissions from year to year. It is easy to assess the historical CO_2 emissions of a retiring unit in a particular baseline year, as the previous examples demonstrate. However, such estimates tend to vary in their selection of baseline year and in any event become quickly out of date. Although the number of units and the aggregated capacity of expected retirements is large, the units that have thus far retired or announced plans to retire tend to mostly be smaller EGUs or EGUs that operate less frequently. The largest, most frequently operated coal EGUs produce the lion's share of coal-fired generation, and few of these units are slated for retirement. Because of these factors, assessments of the reduction in coal-fired EGU emissions that will result from retirements generally represent less than ten percent of total EGU emissions.[41] Furthermore, it must also be understood that retiring units can be replaced by a variety of types of resources, or not replaced at all, and the net emissions reductions attributable to EGU retirement decisions are rarely assessed in a consistent or rigorous way.

35 Tennessee Valley Authority. (2013, November). TVA Board Takes Action to Improve TVA's Operations and Financial Health. [Press release]. Available at: http://www.tva.com/news/releases/octdec13/board_111413.html

36 All emissions data are obtained from the EPA's eGRID database, which can be accessed or downloaded at http://www.epa.gov/cleanenergy/energy-resources/egrid/

37 South Carolina Electric and Gas. (2013, November). SCE&G Retires Canadys Station Power Plant as Part of Strategy to Meet More Stringent Environmental Regulations. [Press release]. Available at: https://www.sceg.com/about-us/newsroom/2013/11/13/sce-g-retires-canadys-station-power-plant-as-part-of-strategy-to-meet-more-stringent-environmental-regulations

38 US Energy Information Administration. (2014, March 20). *Today in Energy*. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15491

39 SourceWatch.org. *Coal Plant Retirements*. Available at: http://www.sourcewatch.org/index.php/Coal_plant_retirements#Projected_retirements_range_from_25.2C000_-_60.2C000_megawawatts

40 GAO. (2014, September). *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*. Available at: http://www.gao.gov/assets/670/665325.pdf

41 See, for example, an assessment reported by *USA Today* at: http://www.usatoday.com/story/money/business/2014/06/08/coal-plant-retirements-barely-cut-carbon-emissions/10008553/

5. Co-Benefits

In addition to the GHG emissions reductions noted previously, EGU retirements will likely result in reductions in emissions of other regulated air pollutants, depending on the fuels burned prior to retirement and the resources used to replace the power generated by the retired EGUs.

The full range of co-benefits that can be realized through EGU retirement are summarized in Table 8-2. The non-GHG air quality benefits are based on an assumption that any plant that is closed will be replaced by either a more efficient fossil-fueled plant, renewable energy, energy efficiency, or a combination of these resources, but the magnitude of the benefits can be expected to vary widely depending on the new resource.

Table 8-2

Types of Co-Benefits Potentially Associated With Retiring Aging Power Plants

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes – for coal-fired EGUs
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	Maybe
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	Maybe
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other: Alternative Land Use	Yes

6. Costs and Cost-Effectiveness

It is common business practice to make decisions based on forward-looking costs, the costs one reasonably expects to confront in the future. A decision to close an EGU is no different, except the costs are measured in millions or billions of dollars, not thousands.[42] As one commentator noted:

> *In general, the owner of a coal-fired power plant (or of any generating facility, for that matter) may decide to retire the plant when the revenues produced by selling power and capacity are no longer covering the cost of its operations. While sometimes these decisions are complex, they essentially can resemble the basic choices that households face, for example, when they have to decide whether making one more repair on an old car is worth it: often, making the repair is more expensive and risky than the decision to trade in that car and buy a new one with better mileage and other features that the old car lacks.*[43]

The costs and cost-effectiveness of an EGU retirement proposal will depend on a number of unique factors related to the physical plant in question, the costs that it is reasonably likely to incur in the future, and regulatory treatment of incurred costs.

Environmental Regulatory Factors

In addition to being subject to standards for GHG emissions under section 111(d) of the Clean Air Act, existing fossil generation sources will be subject to additional environmental regulatory requirements in coming years. The EPA has recently developed regulations under its Clean Water Act and RCRA authority that would

42 Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance With Public Health and Environmental Regulations.* Available at: www.raponline.org/document/download/id/4670

43 Tierney, S. F. (2012, February 16). *Why Coal Plants Retire: Power Market Fundamentals as of 2012.* Analysis Group, Inc. p 2. Available at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf

apply to fossil generators subject to the EPA's Clean Power Plan. Clean Water Act regulations focus on cooling water structures at EGUs, and EGU toxic effluent discharges. RCRA regulations apply generally to solid waste production and containment, in this case, to coal combustion residuals. In addition to promulgating water and solid waste regulations, the EPA has or can be expected to develop a number of standards and regulations under its Clean Air Act authority, including updated National Ambient Air Quality Standards, the Cross-State Air Pollution Rule, and the MATS.[44] For example, the EPA is expected to finalize a revised, more stringent National Ambient Air Quality Standards for ground-level ozone in 2015.

A review of specific compliance costs associated with these environmental programs is beyond the scope of this discussion. However, an integrated review of potential environmental compliance costs would be an appropriate part of the analysis a state might conduct in response to an EGU retirement proposal, inasmuch as the EGU's economic viability and suitability as a utility asset could be affected.

Market Factors

A brief review of market factors may also be instructive for regulators in understanding the role that markets play as they analyze Clean Power Plan compliance options and prepare to make informed decisions on potential EGU retirement proposals. It is important to note, however, that fuel prices and quantities are volatile and are likely to change in the future. After a low in 2012, for instance, natural gas prices have rebounded, as shown in Figure 8-1. Increased domestic natural gas supplies are expected to result in relative price stability and continue to allow gas to compete effectively with other fuels. US coal exports also declined recently owing to a slowing of the Chinese economy and caps placed on the consumption of coal by many Chinese cities and provinces as a way to improve air quality.

The owners of EGUs will consider market factors, including current and projected fuel prices, as part of any retirement or investment decision. A decision to retire a coal-fired EGU that seems cost-effective when coal prices are high and gas prices are low, for example, might not be cost-effective if market conditions change.

Decreasing Cost of Natural Gas

Declining natural gas prices over the past several years owing to the availability of shale gas made available through more effective drilling techniques have made natural gas-fired EGUs more competitive, and this has been a factor in decisions of EGU owners to retire or idle coal plants.[45] Although a number of factors coalesced to cause recent low gas prices,[46] however, other factors suggest that current prices may not necessarily be sustainable.[47]

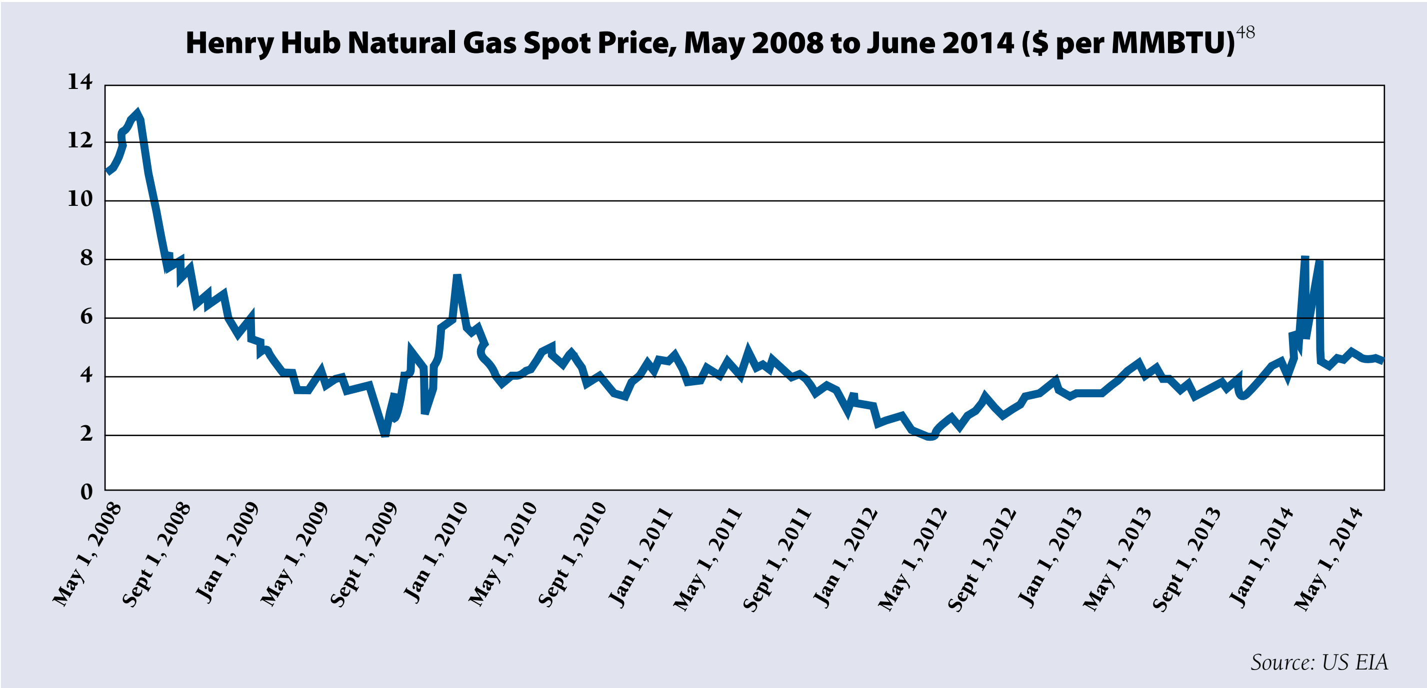
44 The US Energy Information Agency reports that, between 2012 and 2020, approximately 60 GW of coal-fired capacity is projected to retire in the AEO2014 Reference case, which assumes implementation of the MATS standards, as well as other existing laws and regulations. Supra footnote 38.

45 Gerhard, J. (2013). *Coal Plant Closures and US Wholesale Electricity Markets.* In Regulatory Assistance Project Knowledge Management Series (2013). *Complying With Environmental Regulations.* Available at: http://www.raponline.org/featured-work/complying-with-environmental-regulations-a-knowledge-management

46 Including reduced demand owing to economic recession; shale gas production from early high-production sites and gas dumping; price subsidization of dry gas from high "wet gas" and "liquids" prices; the "non-winter" of 2011/2012 (the first four months of 2012 were the warmest January to April in US recorded history); residential and commercial natural gas consumption down more than 18 percent; and gas storage at record levels, and nearing capacity. See: Kushler, M. (2013, October 23). *Natural Gas Prices and Natural Gas Energy Efficiency: Where Have We Been and Where Are We Headed.* Presentation to the Energy Foundation Advocates Meeting, ACEEE. Kushler, M., York, D., & Witte, P. (2005, January). *Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest.* ACEEE, p 5. Available at: http://www.aceee.org/research-report/u051

47 Including increased exports of domestic gas, and gas/electricity interdependence, that is, the greater share of gas-fired electricity production and the risk associated with seasonal demand spikes and storage miscalculation. See, e.g.: Farnsworth, D. (2014). *Further Preparing for EPA Regulations.* Appendix 1 and discussion of natural gas cost risk at pp. 48–52. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6989

Figure 8-1



Excess Natural Gas Generation Capacity

Another factor weighing on the closure of coal plants is the significant amount of underused natural gas generating capacity in the United States. According to a 2011 Massachusetts Institute of Technology study, the existing US natural gas generation fleet has an average capacity factor of approximately 41 percent, whereas its design capacity allows such plants to operate at 85 percent.[49] The EPA, in its analysis supporting the Clean Power Plan proposal, concluded that existing combined-cycle gas plants could reliably operate at an average capacity factor of 70 percent.[50] This unused capacity is sufficient surplus to displace roughly one-third of US coal generation.[51] Thus, as the cost of natural gas comes down, underutilized gas plants have available capacity with which to compete with coal plants and possibly displace them in the dispatch order.[52]

Inherent Efficiency of Natural Gas Plants

Modern natural gas-fueled combined-cycle units are generally more efficient than existing coal plants. Coal and combined-cycle gas plants typically have heat rates of 10,000 BTU/kilowatt-hour (kWh) and 7000 BTU/kWh, respectively. To the degree that coal and gas costs converge, the more efficient natural gas plants will become more economically competitive than their coal counterparts.[53]

Increasing Cost of Coal

Increasing coal costs put additional pressure on the ability of US coal plants to participate in US electricity markets.[54] In many cases, mining and mining-related regulatory requirements have increased, contributing to higher mining costs that are passed along to coal consumers and the closure of some mines. Most notably, however, coal prices have increased every year since 2002, and have done

48 NGA Issue Brief: Natural Gas Price Trends. (2014, August). *Henry Hub Natural Gas Spot Price, May 2008 to June 2014 ($ per MMBtu)*. Available at: http://www.northeastgas.org/nat_gas_price_trends.php

49 Supra footnote 45.

50 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures*. Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

51 Ibid.

52 Supra footnote 45.

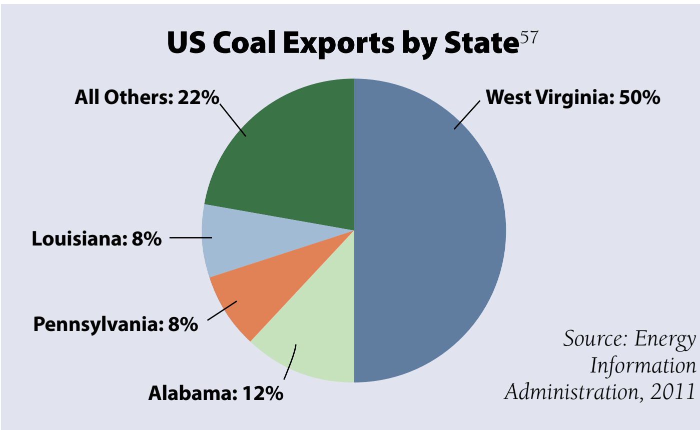
53 Ibid.

54 Ibid.

so in part because of increased exports,[55] particularly to European and Asian markets, and in part because of recent reductions in production in other parts of the world, such as Australia and Indonesia.[56]

According to the National Mining Association, US coal exports increased 31 percent from 2010 to 2011.[58] The average price per ton of coal in 2011 was up 24 percent over 2010, and coal exports represented 9.8 percent of all US coal production in 2011.[59] According to *The Wall Street Journal*, "US coal shipments outside the country in 2014 are expected to surpass 100 million tons for the third year, a record string"[60] (Figure 8-3).

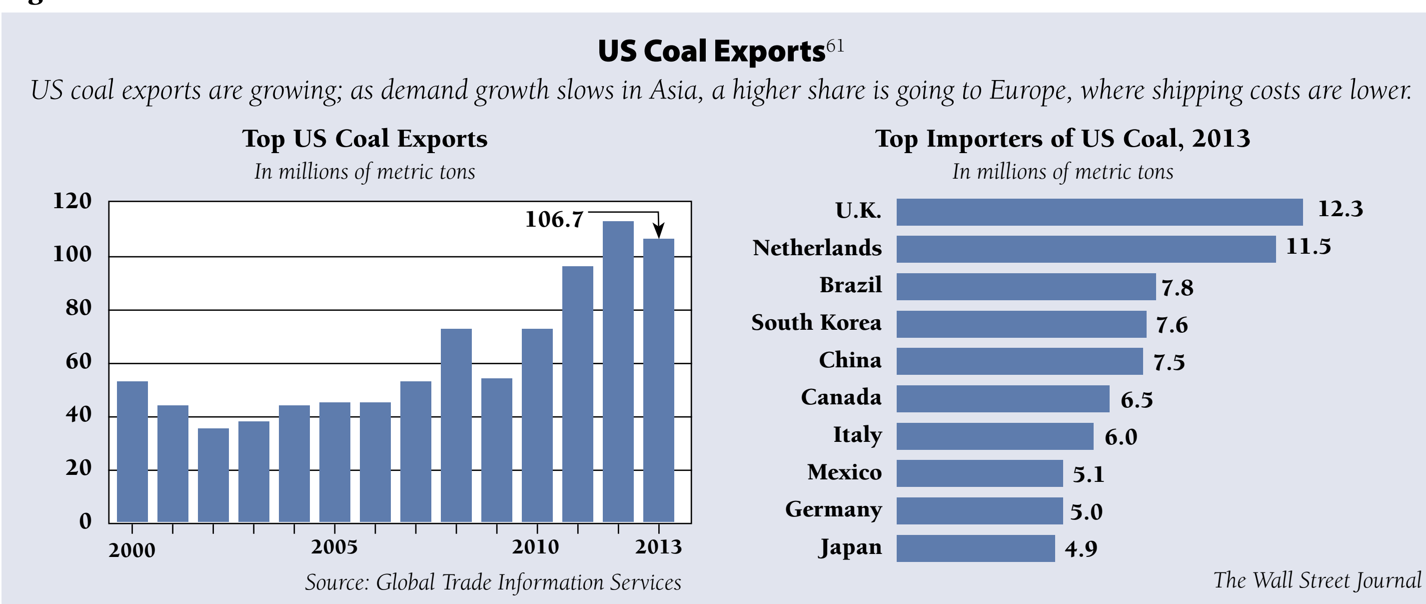
Figure 8-2



Increasing Cost to Transport Coal

The cost of transporting coal to coal-fired generators raises generator costs and can make them less economical to run.[62] Coal plants receive approximately 72 percent of their coal by rail.[63] Costs can range anywhere from 10 percent to almost 70 percent of the delivered price of coal, depending on the type of coal purchased and location of the power plant.[64] The US Energy Information Administration (EIA) reports that rail transportation costs increased from $13.04 to $15.54 per ton (19 percent) from 2001 to 2010.[65] Competition for rail capacity from tight oil producers has exacerbated shipping costs for coal generators.

Figure 8-3



55 Miller, J. W. (2014, March). The New Future for American Coal: Export It. *Wall Street Journal*. Available at: http://online.wsj.com/news/articles/SB10001424052702303563304579447582374789164.

56 Supra footnote 45.

57 Department of Transportation, Federal Highway Administration. (2013). *National Gateway and Corridor Concepts*. Available at: http://www.fhwa.dot.gov/planning/border_planning/gateways_and_corridors/gateway_ops/sec03.cfm (DOT FHWA 2013).

58 Coleman, L. (2012, May). *2011 Coal Producer Survey.* National Mining Association. Available at: http://nma.dev2.networkats.com/pdf/members/coal_producer_survey2011.pdf; Supra footnote 45.

59 Supra footnote 45.

60 Supra footnote 55.

61 Ibid.

62 Supra footnote 45.

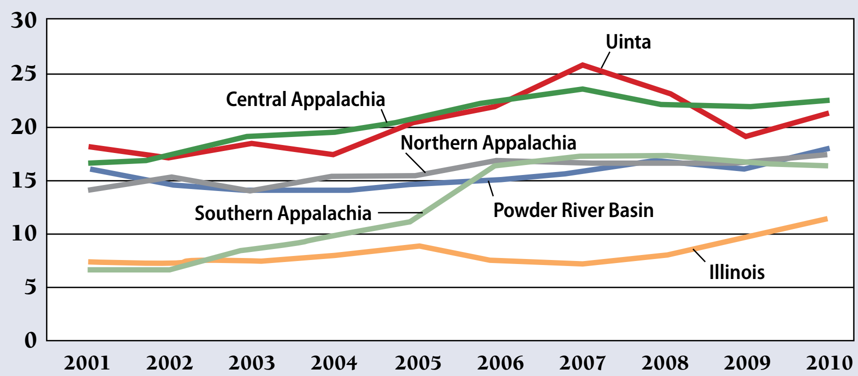
63 Ibid.

64 Ibid.

65 Ibid.

Figure 8-4

Average Rail Transport Cost of Coal to the Power Sector by Major Coal Basin[66]



Source: EIA

Age of Coal Plant Fleet

Another factor that weighs into the decision to retire coal plants is that many of the coal plants under consideration are at or near the end of their economically useful lives.[67] These units tend to have higher fixed and variable operation and maintenance (O&M) costs per megawatt-hour of electricity generated, to be less efficient in generating electricity, and to be more expensive to retrofit than newer units.[68]

Flat or Decreasing Electricity Demand

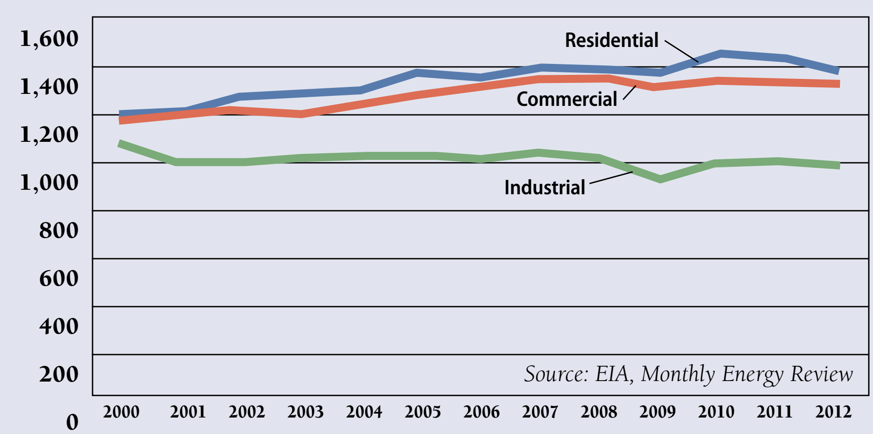
The recent economic downturn and ongoing investments in end-use energy efficiency are combining to flatten load growth and moderate demand for electricity. This in turn lowers potential revenues to generators.[69] In December 2013, the EIA found that "US electricity sales … declined in four of the past five years," driven by declining industrial sales and flat sales in the residential and commercial sectors.[70] This occurred "despite growth in the number of households and commercial building space." And, "The only year-over-year rise in electricity use since 2007 occurred in 2010, as the country exited the 2008-09 recession"[71] (Figure 8-5).

Increasing Competitiveness of Renewable Energy

Several observers have noted that downward trends in the costs of renewable energy are now reaching the point at which they are placing pressure on coal plants at certain times in the year and replacing some coal plants in the dispatch stack.[72] For example, the Analysis Group has

Figure 8-5

Annual Retail Electric Sales by Sector (2000–12)[73]



Note: Direct electricity usage and sales to the transportation sector are not graphed as both account for less than 4% of electricity usage.

66 Association of American Railroads. (2013, August). DOT FHWA 2013. The nation's rail system is a key part in US coal-fired electricity production. According to the Association of American Railroads, coal accounted for nearly 20 percent of rail gross revenue in 2013. https://www.aar.org/ See also: Association of American Railroads. (2014, July). *Railroads and Coal.* Available at: https://www.aar.org/BackgroundPapers/Railroads and Coal.pdf#

67 Supra footnote 45; *Air Emissions and Electricity Generation at US Power Plants.* (2012, April 18). Available at: http://www.gao.gov/assets/600/590188.pdf

68 Depending on the regulatory treatment of coal plant costs, plants may or may not be fully depreciated. See discussion below of "Other Regulatory Factors."

69 Supra footnote 45.

70 US EIA. *Annual Retail Electric Sales by Sector (2000–12).* Today in Energy. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=14291

71 Supra footnote 70.

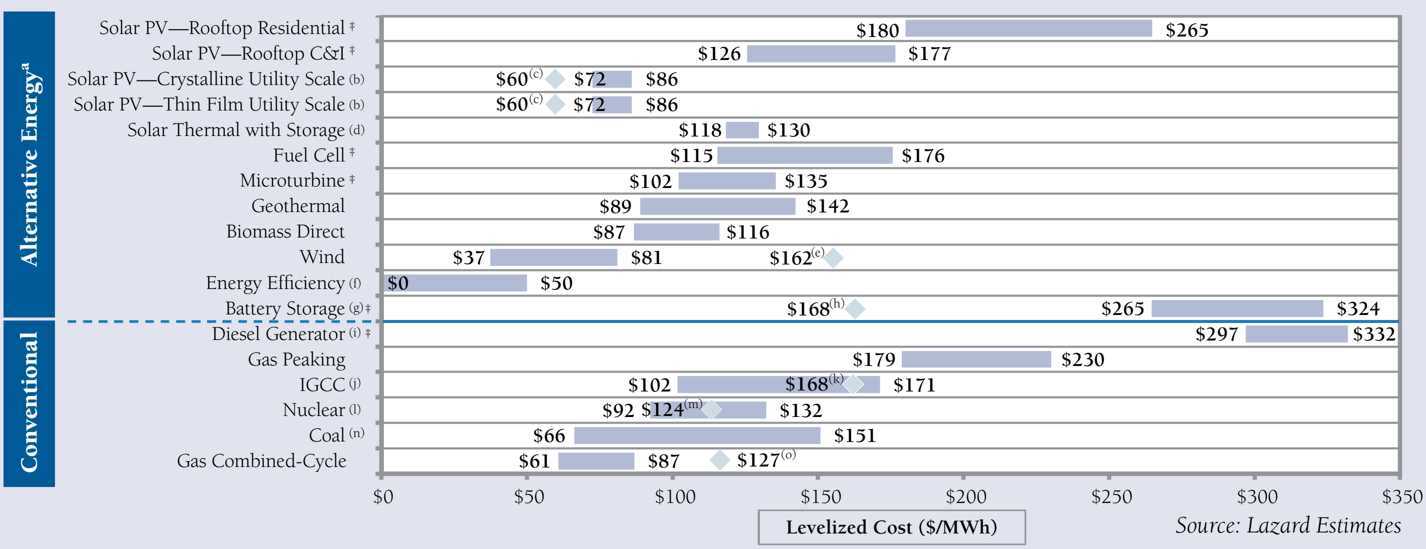
72 Supra footnote 45.

73 Supra footnote 70.

noted that renewables and other distributed resources made up approximately ten percent of PJM's 2014–2015 capacity auction, displacing other generation resources and contributing to "the economic pressure on existing generating resources."[74] In particular, the levelized cost of electricity produced by wind and solar resources dropped by more than 50 percent from 2008 to 2013.[75] Lazard's most recent Levelized Cost of Energy Analysis reveals continuing and significant competitive price improvements of certain renewables against other more traditional resources, as summarized in Figure 8-6. A Deutsche Bank analyst has forecast that by 2016, solar prices will be

Figure 8-6

Lazard's Estimates of Unsubsidized Levelized Cost of Energy (Dollars per MWh)[76]



Source: Lazard Estimates

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Assumes Powder River Basin coal price of $1.99 per MMBtu and natural gas price of $4.50 per MMBtu. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

a. Analysis excludes integration costs for intermittent technologies. A variety of studies suggest integration costs ranging from $2.00 to $10.00 per MWh.

b. Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest US). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

c. Diamond represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

d. Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

e. Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.

f. Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely. Estimates involving demand response may fail to account for opportunity cost of foregone consumption.

g. Indicative range based on current stationary storage technologies; assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

h. Diamond represents estimated implied levelized cost for "next generation" storage in 2017; assumes capital costs of $300/KWh for six hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% and fixed O&M costs of $5.00 per KWh installed per year.

i. Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

j. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

k. Represents estimate of current US new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.

l. Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

m. Represents estimate of current US new nuclear construction.

n. Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

o. Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

74 Supra footnote 43.

75 Silvio Marcacci. (2013, September 20). Analysis: 50 Percent Reduction In Renewable Energy Cost Since 2008. Commentary on "Lazard's Levelized Cost of Energy Analysis—Version 7.0." The Energy Collective. [Web log post]. Available at: http://theenergycollective.com/silviomarcacci/276841/analysis-50-reduction-cost-renewable-energy-2008

76 Lazard, J. (2014, September). *Lazard's Levelized Cost of Energy Analysis – Version 8.0.* Available at: http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

competitive with or lower than those of average power prices in 36 states; solar is already competitive today in ten states.[77]

Poor Load Forecasting

One source cited poor load forecasting as a reason some plants may be retired, saying, "As changes in demand and the economy evolved, some utilities acknowledged weaknesses in the forecast models used by the industry to project future electricity use. When overstated load forecasts were identified, the new plant was no longer viable."[78]

The previous discussion illustrates that numerous forward-looking market factors affect plant closure decisions by plant owners and regulators. Understanding the role of these factors can help in weighing the relative merits of plant closure proposals, because the central question facing regulators is whether plant closures are cheaper and less risky than alternative compliance options.

7. Other Considerations

As the prior discussion illustrates, the cost-effectiveness of a plant closure proposal needs to be determined on a case-by-case basis, but there are some useful general observations that can be made. Older power plants in many ways are at a disadvantage when compared to newer generation resources. In a market context, retirement is considered when the potential income for the unit is no longer sufficient to justify the unit's continued O&M. This may be attributable to such factors as fuel costs, regulatory pressure, or costs of required controls that combine, making it no longer economically justifiable to continue to maintain the unit in operable condition.

Comparative fuel costs and underutilized and more efficient capacity all contribute to the inability of older generating resources to compete economically. This is why conventional wisdom holds that old power plants are more suitable for retirement. For example, a plant's age was a major factor in a 2013 M.J. Bradley and Associates analysis of pending coal retirements in which it found that most of the 52 GW of coal units slated for retirement by 2025 are "small in size, lack environmental controls, and are over 50 years old"[79] (Table 8-3). In 2012, the US GAO reached similar conclusions in "Air Emissions and Electricity Generation at US Power Plants," a study that examines older EGUs.[80]

Although utility decisions related to plant closure are largely driven by the age of a power plant, they are also heavily influenced by whether or not a company will be able to recover a plant's undepreciated costs – despite the

Table 8-3

Coal Retirements as of March 2013 [81]

Characteristic	Announced for Retirement (since January 2006) by 2025	Overall US Fleet
Capacity	52 GW	322 GW
Units	340	1264
Unit Age (avg)	54 years	43 years
Unit Size (avg)	153 MW	254 MW
Utilization (avg in 2011)	49%	71%
Regulated (% of capacity owned by vertically integrated utilities)	70%	75%

77 Walton, R. (2014, October 30). *Study: At Least 36 States Will See Solar Hit Grid Parity by 2016.* Utility Dive. Available at: http://www.utilitydive.com/news/study-at-least-36-states-will-see-solar-hit-grid-parity-in-2016/327286/

78 Supra footnote 45.

79 Saha, A. (2013, April 12). *Review of Coal Retirements.* M.J. Bradley & Associates, LLC. Available at: http://www.mjbradley.com/reports/coal-plant-retirement-review

80 US GAO. (2012, April 18). *Air Emissions and Electricity Generation at US Power Plants.* Available at: http://www.gao.gov/assets/600/590188.pdf. In this study the US GAO defines "older plants" as having been in operation "in or before 1978."

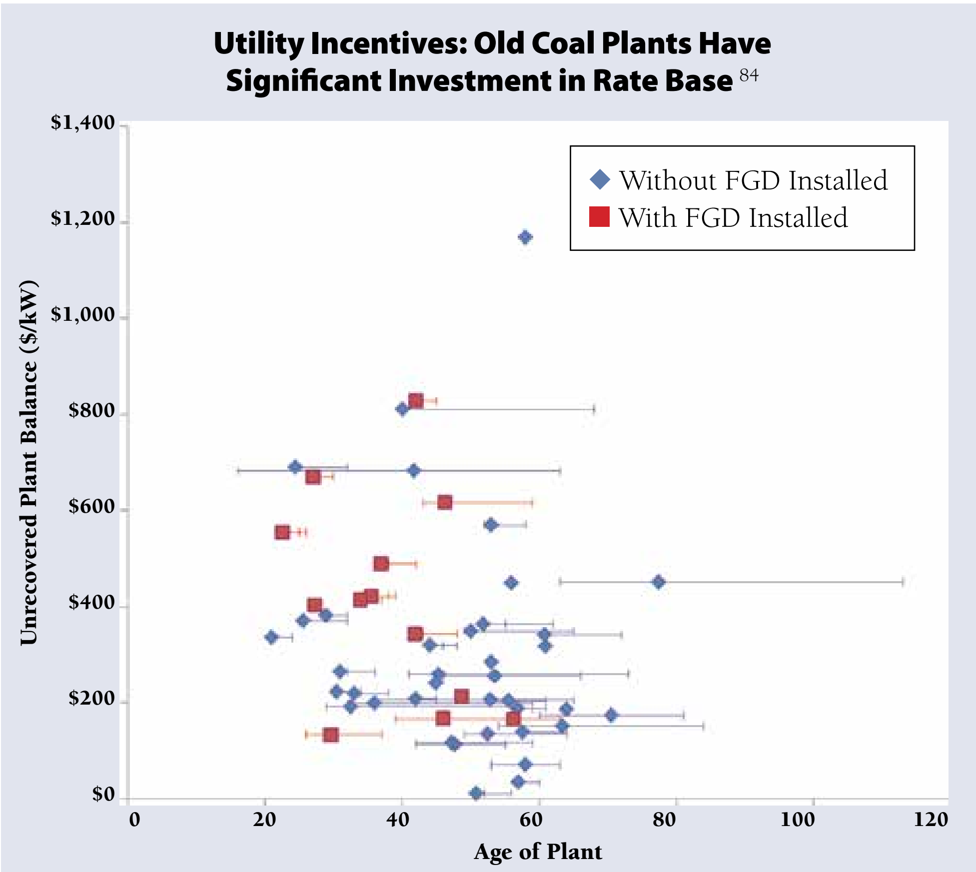
81 Based on *Coal Retirements,* in: supra footnote 79.

plant's age.[82] Plant owners are understandably reluctant to face such "stranded costs" where they lack certainty of recovery from ratepayers.

Nationwide information on plant depreciation is not readily available because depreciation studies are typically confidential. But based on one sample derived from non-confidential studies, plants may have hundreds of dollars per kilowatt of unrecovered value on the books, as illustrated in Figure 8-7.[83]

In this sample, comprising 52 coal plants owned by 11 utilities, the average plant age (weighted by capacity) is approximately 47 years. Average plant capacity is approximately 675 MW. Average unrecovered plant balance is approximately $336/kilowatt. And the unrecovered balance is over 50 percent of total plant balance.

Figure 8-7



As noted earlier, older plants are less likely to be dispatched, and if they are not running, then they are at risk of not recovering their fixed operations and maintenance costs and undepreciated plant costs, an untenable outcome from both an economic and regulatory perspective. Not only are older plants more likely to be producing less revenue, typical regulatory practice for utility-owned generating units requires those investments to be "used-and-useful" in order to be recovered in utility rates.[85] Although a used-and-useful determination is complex and fact-specific, there are some general observations relevant to power plant closures that can be made with regard to this doctrine.[86]

82 See, e.g.: Wishart, S. (2011, September 27). *Coal Retirement vs. Refurbishment – The Role of Energy Efficiency.* Delivered at ACEEE National Conference on Energy as a Resource. Available at: http://aceee.org/ Important economic drivers for coal retrofit versus retirement include: costs of environmental controls (capital and O&M), replacement capacity; replacement energy; CO_2 assumptions; current rate base; and accelerated depreciation.

83 Synapse Energy Economics collected information from 52 coal plants owned by 11 companies.

84 Biewald, B. (2014, January 21). *The Future of Coal: Economics and Planning.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/Downloads/SynapsePresentation.2014-01.0.Future-of-Coal.S0091.pdf

85 Lazar 101 at 39. Electricity prices are set by utility commissions in rate cases. In these investigations, commissions review company costs, including those associated with power plant investment, and determine which are appropriate and suitable for recovery in rates. In rate cases, companies justify their costs, which can include expenses associated with fuel, O&M, purchased power, and other administrative-related activities. These considerations only apply to utility-owned generating units. Generating units that are owned by independent power producers and operating in a wholesale market will make retirement decisions based on whether potential income for the unit is sufficient to justify the unit's continued O&M, as previously noted.

86 When a new power plant enters service and its costs are considered for inclusion in rates, regulators often perform a "prudence review" to determine if the plant was built in an economic manner. If regulators determine that the planning or construction was imprudent, they can disallow a portion of the investment, and refuse to include it in the company's rate base. Lazar at 39.

For a facility to be considered "used" means that the facility is actually providing service. Being "useful" means that without the facility, either costs would be higher or the quality of service would be lower.[87] In rate investigations, the utility has the burden of proving that an investment meets this test, but utilities often enjoy the presumption of used-and-usefulness in the absence of evidence to refute it.[88] In circumstances in which plant investment is found to not be used-and-useful, its costs are not allowed in utility rates. This is one reason plant closure is such a sensitive topic. Companies with generating units that are marginal and barely operational are at risk of being determined to not be used-and-useful. And companies do not want to see this happen, because it will directly compromise their ability to receive the full recovery of their investment.[89]

Not surprisingly, finding a plant to not be used-and-useful also poses political and economic ramifications for utility commissions and public advocates. This is why commissions may only respond obliquely to utilities in this regard. Commissions might observe, for example, that the economics of a plant are questionable. They might provide "signals" to utilities about the propriety of making further investments in a plant, perhaps suggesting that if an investment is undertaken the commission will take a "hard look" at that utility decision, or if there are related cost overruns, the company's shareholders and not the ratepayers can be expected to shoulder these costs.

An additional observation: the previous discussion has described "typical" regulatory practice. A plant closure undertaken for purposes of compliance with a Clean Air Act requirement may not be typical. This is a significant distinction that companies may make and that utility commissions could take into consideration. For example, although granting recovery of costs that would otherwise not be deemed used-and-useful is not recommended, an investigation might conclude that granting recovery of undepreciated costs associated with the retirement of older power plants is a more cost-effective approach compared with other Clean Power Plan compliance alternatives, and is thus worthy of inclusion in a state plan.

An example from the state of Alabama of regulatory accounting treatment of a utility plant may be instructive. In August 2011, Alabama Power petitioned the Alabama Public Service Commission for an authorization "related to cost impacts that could result from the implementation of new [EPA] regulations."[90] More specifically, Alabama Power sought:

> *Authorization to establish a regulatory asset on its balance sheet in which it would record the unrecovered investment cost associated with full or partial unit retirements caused by such regulations, including the unrecovered plant asset balance and the unrecovered cost associated with site removal and closure.*[91]

The Commission granted the company's request, allowing it to put in place an accounting approach designed "to benefit customers by addressing certain potential cost pressures they would otherwise face."[92] The Commission went on to explain:

> *Should environmental mandates from EPA result in the Company prematurely retiring a generating unit or partially retiring certain unit equipment in order to effectuate the transition of that unit's operational capability to a different fuel type, the Company will be able, through these authorizations, to recover the remaining investment costs, as well as expenses associated with unused fuel, materials and supplies, over the time period that would have been utilized for that unit, but for the [EPA's] mandates.*[93]

87 Lazar at 39.

88 Ibid.

89 Utilities and utility regulators cannot predict with perfect accuracy whether an EGU will be used and useful at some future data. The possibility of stranded costs is a factor in nearly every decision about whether to retrofit or retire a utility-owned EGU. The Regulatory Assistance Project has cited best practices on this topic and offered recommendations to utility regulators in two publications on environmental regulations: (1) Lazar, J. & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/4670; and (2) Farnsworth, D. (2014, January). *Further Preparing for EPA Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6989

90 Alabama PSC Docket U-5033, Order: September 7, 2011. Available at: https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=132f89da-98f5-4c6d-b218-c7a116224e1e at p. 1-2.

91 Supra footnote 90 at p. 2.

92 Ibid at p. 7.

93 Supra footnote 92.

On one hand, it is perhaps surprising that the utility was given preapproval for such a potentially large amount of costs, with no specific plan identifying specific regulations at issue and the actual or likely costs that the utility may face in order to comply. Information related to reasonably anticipated costs, the specific environmental regulations requiring these investments, and justification by the company for the compliance approaches it chose would normally be a condition for such preapproval. It would seem that regulators should have an opportunity to review the company's comprehensive analysis evaluating the value of the preapproved project under a range of possible outcomes. On the other hand, a policy like this allows a company to come forward and propose plant closures as an option that a state commission might reasonably consider for its cost-effectiveness and overall effectiveness. In this case, making a regulatory determination about cost recovery for unamortized rate-base balances for retiring coal plants could be an important and appropriate part of a plant's retirement plan and the state's compliance plans.

As with many regulatory matters in practice, there are balances to be struck. Rate trajectory over the transitional period is an important aspect, along with such issues as incremental carrying costs and key debt ratios. Given the regulatory status quo, in which companies are unlikely to draw attention to an uneconomic resource owing to concerns over disallowance, a policy like Alabama's could encourage utilities to consider plant retirements as an option for compliance with the EPA's Clean Power Plan requirements.

8. For More Information

Interested readers may wish to consult the following documents for more information on retiring aging power plants:

- Farnsworth, D. (2011). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance*, pp. 20–38 for a more detailed discussion of integrated planning. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/919
- Farnsworth, D. (2014). *Further Preparing for EPA Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6989
- Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance with Public Health and Environmental Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4670
- US EPA. (2014, June). *Technical Support Document (TSD): Resource Adequacy and Reliability Analysis.* Office of Air and Radiation. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf
- Tierney, S. F. (2012, February 16). *Why Coal Plants Retire: Power Market Fundamentals as of 2012.* Analysis Group, Inc. p 2. Available at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf
- US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units — GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

9. Summary

Although closing an aging EGU can be a disruptive and challenging process, when weighed against various alternatives, it may provide a lower-cost solution and be worthy of inclusion in a state's plans for Clean Air Act compliance, including compliance with Clean Power Plan requirements.

There are various regulatory contexts in which states can review proposals to close power plants. There are also numerous factors that can affect decisions to keep a plant running or to retire it, including forward-looking market considerations, environmental regulatory requirements, and the ability to recover past plant-related investments.

States that consider plant closure as a compliance option will have to consider these issues, and the varying degree to which these factors support such a decision. However, states that do engage in this effort will be better prepared to evaluate a wider array of potential compliance options, and better able to strike their preferred balance between cost and other policy goals, including the most affordable and reliable compliance scenarios allowable under the EPA's Clean Power Plan.

9. Switch Fuels at Existing Power Plants

1. Profile

One option for reducing the carbon dioxide (CO_2) emissions from an existing electric generating unit (EGU) is to switch to a lower-emitting fuel. Fuel switching is perhaps the most familiar and most proven method for reducing greenhouse gas (GHG) emissions from existing EGUs. The technological challenges are familiar and manageable, the co-benefits can be substantial, and the costs are generally lower than for other technology options.[1]

Fuel switching can involve at least three distinct strategies. First, if an EGU is already designed and permitted to use multiple fuels, the owner or operator can reduce annual emissions by increasing the use of a lower-emitting backup fuel and decreasing the use of a higher-emitting primary fuel. For example, the EGU could reduce annual combustion of coal and increase annual combustion of natural gas. With this strategy, the hourly emissions rate of the EGU when it is burning coal would not change, and the hourly emissions rate of the EGU when it is burning gas would not change, but its annual emissions would decrease.

The second strategy is to blend or cofire a lower-emitting fuel with a higher-emitting fuel. For example, the owner or operator of the EGU could blend two different ranks of coal, or cofire a biomass fuel with coal, to reduce the emissions rate of the unit.

The third fuel-switching strategy is to repower the EGU, that is, to modify the unit or the fuel delivery system to accommodate the use of a lower-emitting fuel not previously used. For example, a coal-fired EGU might be reconstructed to burn natural gas, thus reducing the unit's emissions rate.

Switching fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking. For any existing EGU, there are reasons the current fuels are used and other fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, permit conditions, emissions of criteria or toxic air pollutants, availability of natural gas pipeline capacity, and so forth.

Switching fuels will be most feasible from a technological perspective where an EGU is already designed and permitted to combust more than one type of fuel, but the current primary fuel has a higher input emissions factor than the secondary fuel. Even so, economic considerations will determine whether fuel switching is a practical option. Blending or cofiring strategies can introduce additional difficulties, as the use of blended fuel or cofiring of two fuels may affect the performance of the fuel delivery system, boiler, pollution control devices, ash handling system, and the like. Repowering projects tend to be major undertakings requiring considerable capital investment.

2. Regulatory Backdrop

With few exceptions, fuel switching has not been imposed on regulated entities as a statutory or regulatory requirement, nor has it been mandated through air pollution permitting processes. It is normally adopted by regulated entities as either an economic choice or as an optional strategy for complying with environmental requirements.

The US Environmental Protection Agency (EPA) evaluated fuel switching as a potential GHG abatement measure in conjunction with the June 2014 proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric

1 This chapter focuses exclusively on switching the fuels used (or the proportions in which they are used) at existing power plants to reduce onsite emissions without necessarily reducing electrical output. Note that Chapter 21 addresses a different strategy that is often explained in other publications using the same term "fuel switching." Chapter 21 examines the potential to reduce CO_2 emissions by less frequently dispatching (i.e., operating) higher-emitting power plants (e.g., coal units) while increasing the dispatch frequency of other, lower-emitting power plants (e.g., gas units).

Utility Generating Units. Chapter 6 of the GHG Abatement Measures Technical Support Document (TSD) is dedicated to fuel switching.[2] In the TSD, the EPA analyzed the GHG reduction potential, co-benefits, and cost-effectiveness of cofiring natural gas or biomass with coal, and of repowering a coal unit to 100 percent gas or biomass. Based on its analysis, the EPA concluded that fuel switching should not be included as part of the "best system of emissions reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities." Details of the EPA's analysis and conclusions are provided later in this chapter.

Most federal and state air pollution regulations have been implemented in a "fuel-specific" way that results in separate emissions limits, control requirements, and compliance demonstration methods for each fuel that a source is permitted to burn. The emissions limits and other applicable requirements for each fuel tend to be based on what is realistically achievable when burning that fuel.[3] Part of the explanation for this approach comes from a precedent-setting 1988 permit decision in which the EPA Administrator held on appeal that "...permit conditions that define these [control] systems are imposed on the source *as the applicant has defined it.* Although imposition of the conditions may, among other things, have a profound effect on the viability of the proposed facility as conceived by the applicant, the conditions themselves are not intended to redefine the source."[4]

In the context of the federal Prevention of Significant Deterioration (PSD) regulations, the EPA has held since that 1988 decision that control options that "fundamentally redefine the source" may be excluded from a best available control technology (BACT) analysis, but state and local permitting authorities have the discretion to engage in a broader analysis if they so desire. A number of past EPA statements in guidance documents and precedents in the case of actual permit applications indicate that requiring (for example) a coal-fired EGU to switch to natural gas as the BACT would be to "fundamentally redefine the source."[5] In summary, state and local permitting authorities have the discretion to consider fuel switching as a possible BACT option but, under current EPA policy, they are not required to do so. In practice, fuel switching has historically rarely been considered in BACT analyses.

Nearly all of the exceptions to the traditionally "fuel-specific" approach to regulation come from federal or state regulations that in some way cap annual emissions of a specified pollutant from a category of sources. Examples of such "fuel neutral" regulations include the federal Acid Rain Program, the federal Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule, and the Regional Greenhouse Gas Initiative (RGGI). Regulations like these that include a mass-based annual emissions cap do not force sources to switch fuels but allow for fuel switching as one of many possible compliance strategies.

Colorado's *Clean Air – Clean Jobs Act* provides a different kind of exception to the fuel-specific generalization.[6] This state statute, enacted in 2010, did not create annual mass-based emissions limits, but required the state's largest public utility to develop a coordinated plan for reducing emissions from coal-fired power plants in sufficient amounts to satisfy current *and anticipated future* Clean Air Act requirements. Here again, fuel switching was not mandated by the legislation but the reductions were targeted toward coal-fired plants, and fuel switching was specifically listed as one of the options available to the utility for inclusion in the plan.

Along a similar vein, in 2011 the State of Washington enacted a law that imposes a GHG emissions performance standard for the two boilers at an existing coal-fired power plant. The law does not require fuel switching per se, but the standards are sufficiently stringent that the source is

2 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

3 During the permitting process, regulators occasionally find that a source will be unable to meet all applicable requirements while burning a particular fuel. In such cases, the owner of the source might opt to switch to a different fuel in order to obtain the permit, or accept limitations on the quantity of the problematic fuel that will be combusted, but the regulator will not unilaterally mandate fuel switching.

4 In re Pennsauken County, N.J., Resource Recovery Facility, 2 E.A.D. 667 (Adm'r 1988) (emphasis added).

5 *See, e.g.,* In re Old Dominion Elec. Coop., 3 E.A.D. 779 (Adm'r 1992), in which the EPA found no error in a state's determination that it could not require a proposed new coal-fired EGU to instead fire natural gas.

6 Colo. Rev. Stat. §§ 40-3.2-201 to 40-3.2-210.

Table 9-1

Compliance Methods Used in Phase 1 of the Acid Rain Program

Compliance Method	Number of Generators	Average Age[a] (years)	Affected Nameplate Capacity (megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	1995 Emissions (tons)	Percentage of Total Nameplate Capacity Affected by Phase I	Percentage of SO_2 Emission Reductions in 1995[c]
Fuel Switching and/or Blending	136	32	47,280	2,892,422	4,768,480	1,923,691	53	59
Obtaining Additional Allowances	83	35	24,395	1,567,747	2,640,565	2,223,879	27	9
Installing Flue Gas Desulfurization Equipment (Scrubbers)	27	28	14,101	923,467	1,637,783	278,284	16	28
Retired Facilities	7	32	1,342	56,781	121,040	0	2	2
Other	8	33	1,871	110,404	134,117	18,578	2	2
Total	**261**	**32**	**88,989**	**5,550,821**	**9,301,985**	**4,444,432**	**100**	**100**

widely expected to either shut down or repower by 2025. The installation of carbon capture and storage technology might provide a third compliance option that allows for continued use of coal.[7]

Fuel switching strategies may have permitting implications for existing sources. In cases in which an EGU is already permitted to burn more than one fuel, it will often be the case that the source can increase its use of a lower-emitting fuel without requesting any changes to its operating permit because the emissions rates will not change. There may be exceptional cases in which a source that has a limit on annual or monthly mass emissions or hours of operation will need to request a permit revision in order to increase its use of a fuel for which it is already permitted. If the owner of an EGU wishes to switch to a fuel that the source was already capable of burning but was not permitted to burn (i.e., a switch that does not require a physical change to the source), it will be necessary to obtain a revised operating permit. Finally, if the source will be repowered, it may require a new source construction permit and a revised operating permit.

3. State and Local Implementation Experiences

As noted earlier in this chapter, there are virtually no examples of state or local governments that have instituted fuel switching through a mandatory statute or regulation. However, there are abundant examples from virtually all states in which fuel switching has been implemented by sources as a Clean Air Act compliance strategy or for economic reasons (with emissions reductions as a co-benefit). One such example can be found in a 1997 US Energy Information Administration (EIA) review of the compliance strategies adopted by regulated units during the first phase of the Acid Rain Program.[8] As shown in Table 9-1, fuel switching and fuel blending were the chosen strategies for more than half the affected sources, and those strategies accounted for nearly 60 percent of the sulfur dioxide (SO_2) emissions reductions.

An EIA 2012 survey of generators identified over 3600 EGUs that were operable at that time and had the regulatory permits needed to burn multiple fuels.[9] Multi-fuel facilities were operating in every state. With so many EGUs already designed and permitted to burn multiple fuels, the strategy of switching between primary and backup fuels to reduce emissions will be familiar to many power plant owners and state regulators. This is especially true in ozone non-attainment areas that have been subject to seasonal nitrogen oxides (NO_x) emissions limits. It is quite common in such cases for regulated entities to switch to burning natural gas, normally a backup fuel, to meet seasonal limits. Similar strategies have also been used by owners of Acid

7 The possibilities for reducing CO_2 emissions from existing power plants through carbon capture and storage technologies are addressed in Chapter 7.

8 US EIA. (1997, March). *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*. Washington, DC.

9 US EIA. (2013, December 4). Form EIA-860 detailed data for 2012 retrieved from the EIA website: http://www.eia.gov/electricity/data/eia860/index.html.

Rain units (as already noted) and EGUs subject to CAIR in order to comply with annual SO_2 emissions limits. In fact, more than half of the coal-fired EGUs in the Acid Rain and CAIR programs have not installed SO_2 emissions controls, but have complied using fuel switching or other strategies such as allowance trading.[10]

In 2012, electric power industry analysts at the firm SNL Energy reported the results of their review of recent fuel switching at multi-fuel facilities.[11] SNL Energy looked at reported fuel use data to identify power plants capable of burning both coal and natural gas. Overall, 197 facilities (many with multiple EGUs) with a total generating capacity of 78,544 megawatts (MW) were identified as burning both coal and natural gas for electricity generation during at least one month between 2008 and 2012. SNL Energy reported that the volume of gas burned at those plants increased 11 percent in 2011 compared to 2008, whereas the volume of coal burned fell nine percent. These data offer a clear indication that substantial levels of fuel switching can occur at multi-fuel facilities over a relatively short period of time (years rather than decades). What is not quite as clear is how much *additional* fuel switching, beyond what already happened in 2012, is still possible for existing multi-fuel facilities.

Fuel blending has also been a common Acid Rain and CAIR compliance strategy. Many boiler owners in the United States have routinely blended lower-sulfur sub-bituminous coal with higher-sulfur bituminous coal to reduce annual SO_2 emissions while meeting other performance and cost objectives. Unfortunately, most of the analyses of Acid Rain and CAIR compliance strategies have conflated fuel blending with other forms of fuel switching, so it is difficult to quantify how much fuel blending has occurred.

Cofiring is yet another variation on fuel switching. The Electric Power Research Institute (EPRI) published a technical report in 2000 that assessed five proven technologies and one experimental technology for cofiring natural gas with coal at EGUs.[12] EPRI closely examined over 30 full-scale installations of these technologies that had been installed across the entire range of coal-fired boiler types in use in the United States: tangentially fired boilers, wall-fired boilers, cyclone boilers, and turbo-fired boilers. The technologies and installations reviewed are summarized in Table 9-2; for complete descriptions refer to the EPRI report.

The 2012 EIA survey data cited above offers a more recent and comprehensive look at cofiring capabilities in the United States across all technologies and fuels. The EIA data indicate that 1980 of the multi-fuel generating EGUs in the United States have cofiring capability and the necessary regulatory approvals. Although the earlier EPRI report focused only on cofiring coal and gas, the EIA data show that the most common configuration among these units is the ability to cofire oil with gas, as shown in Figure 9-1.

Table 9-2

Cofiring Technologies Reviewed in EPRI Study
(Circa 2000)

Technology	Number of Installations
Supplemental Gas Cofiring (simultaneous firing of both fuels through separate burners in boiler's primary combustion zone)	10
Gas Reburning (in secondary combustion zone)	11
Fuel Lean Gas Reburning	6
Advanced Gas Reburning	2
Amine-Enhanced Fuel Lean Gas Reburning	2
Coal/Gas Cofiring Burners	0

Repowering of existing EGUs is the last type of fuel switching examined in this chapter. In recent years, dozens of repowering projects have been undertaken, announced, or proposed for United States power plants. Most of these projects involve repowering existing coal units to burn natural gas, but there are also several examples involving a switch from coal to biomass. An example of a coal plant that has already been converted to natural gas can be found at Dominion Virginia Power's 227-MW Bremo Power Station in Bremo Bluff, Virginia. Examples of completed coal to biomass repowering projects include

10 US EPA. (2013). *Clean Air Interstate Rule, Acid Rain Program, and Former NOx Budget Trading Program: 2012 Progress Report.* Available at: http://www.epa.gov/airmarkets/progress/ARP-CAIR_12_downloads/ARPCAIR12_01.pdf.

11 SNL Energy reports are available only to subscribers but are frequently cited in trade media accounts. For example, the data reported here appeared in *Coal Age News* (http://www.coalage.com/features/2386-us-power-plants-capable-of-burning-coal-and-natural-gas.html) in October 2012.

12 EPRI. (2000). *Gas Cofiring Assessment for Coal-Fired Utility Boilers.* Palo Alto, CA.

Figure 9-1

Cofiring Configurations Among US Electric Generating Units (2012)

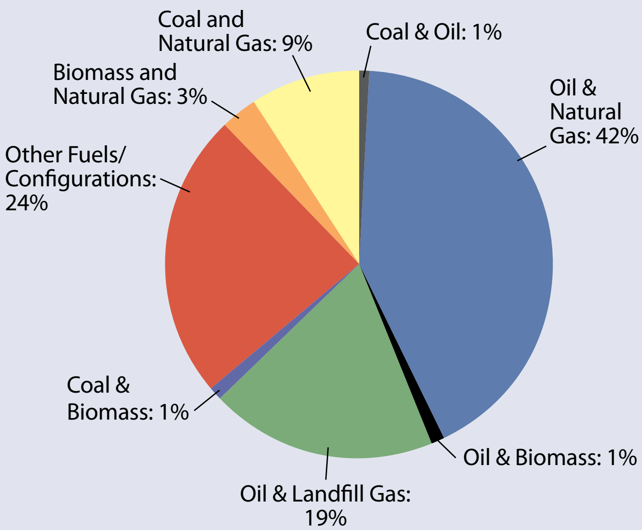
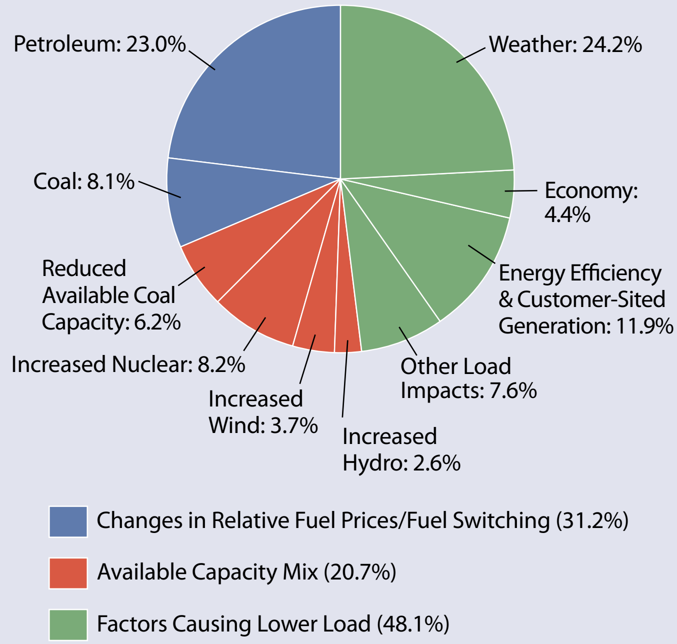


Figure 9-2

CO_2 Emissions Reductions at RGGI Sources From 2005 to 2009[15]



RGGI CO_2 Emissions:
2005: 184.4 million tons 2009: 123.7 million tons
Decrease: 60.7 million tons

DTE Energy Services' 45-MW power plant at the Port of Stockton in California and a 50-MW unit at Public Service of New Hampshire's Schiller Station in Portsmouth, New Hampshire.

Looking ahead, an April 2014 review by SNL Energy found that utilities and merchant power plant owners have announced plans to repower 7600 MW of current coal-fired generating capacity with other fuels, and an additional 3600 MW of coal capacity is slated for either repowering or retirement, with those decisions to come at a later date.[13]

4. GHG Emissions Reductions

To date, switching fuels at existing facilities has occurred primarily in response to criteria pollutant and air toxics regulations and as an economic choice driven by low natural gas prices. However, in nearly all parts of the country, federal GHG regulations for existing sources could conceivably provide the impetus for additional fuel switching beyond what has already happened and what is already planned.

Most of the state experience to date with mandatory CO_2 emissions limits for existing sources comes from the states participating in RGGI.[14] One analysis by the New York State Energy Research and Development Authority (NYSERDA), summarized in Figure 9-2, found that sources regulated under RGGI reduced their CO_2 emissions by 60.7 million tons (33 percent) between 2005 and 2009, and 31 percent of the reductions could be attributed to fuel switching. This underscores two facts: that significant CO_2 emissions reductions are achievable over a short time period, and that fuel switching can be a preferred option for reducing CO_2 emissions.

13 As reported in *Coal Age News* at http://www.coalage.com/61-uncategorised/3572-coal-unit-conversions.html.

14 The nine states currently participating in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey was previously a participant. California, like the RGGI states, has enacted a mandatory CO_2 cap-and-trade program for existing sources including but not limited to power plants. But in the case of California, similar data on emissions reductions and the factors causing them are not yet available because 2013 was the first year for enforceable compliance obligations. California regulators expect fuel switching to play a relatively smaller role than it has in the RGGI states because most of that state's generating fleet is already gas-fired.

15 NYSERDA. (2010, November 2). *Relative Effects of Various Factors on RGGI Electricity Sector CO_2 Emissions: 2009 Compared to 2005.* Available at: http://www.rggi.org/docs/Retrospective_Analysis_Draft_White_Paper.pdf.

At a theoretical or hypothetical level, the output emissions rate of any combustion unit can be determined as follows:

E = EF * HR where
E = output emissions rate (lbs CO2/MWh[16]gross);
EF = input emissions factor (lbs CO2/MMBTU[17]); and
HR = heat rate (MMBTU/MWhgross).

The input emissions factor is a function of the carbon and heat content inherent in the chemical and physical composition of any given fuel; it varies across fuel types and even within fuel types, as shown in Table 9-3. One option for reducing the CO_2 emissions from an existing EGU is to switch to a fuel that has a lower input emissions factor. (Another but very different option, discussed in Chapter 1, is to improve the heat rate of the unit.)

The data in Table 9-3 suggest the levels of emission reductions that are at least hypothetically possible from fuel switching. To begin with, it should be noted that there is a range of emissions factors within most coal ranks. This suggests the possibility that some sources may be able to reduce their output emissions rate by a small amount, but probably no more than five percent, simply by obtaining coal of the same rank that has a lower input emissions factor. Significantly greater reductions are possible if a source switches to an entirely different fuel. For example, switching from lignite coal to natural gas could cut an EGU's output emissions rate nearly in half.

Table 9-3

Average Input Emissions Factors of Various US Fuels[18]

Fuel Type	Input Emissions Factor (lbs CO_2/MMBTU)
Coal – Anthracite	227
Petroleum Coke	225
Coal – Lignite	212 to 221
Coal – Sub-bituminous	207 to 214
Coal – Bituminous	201 to 212
Residual Oil	174
Distillate Oil	161
Natural Gas	117

One fuel switching option that has received considerable attention is the option of blending or cofiring biomass or waste-derived fuels with coal, or completely repowering a coal-fired unit to burn only biomass. Table 9-3 does not show input emissions factors for biomass, biogas, or municipal solid waste fuels. This is because there is significant ongoing debate and controversy about whether or to what extent to treat such fuels as "carbon neutral" (i.e., attribute no net CO_2 emissions to these fuels). The scientific arguments in that debate are beyond the scope of this document, but the salient point is that the regulatory treatment of GHG emissions from biomass and waste-derived fuels remains uncertain at this time and is likely to strongly influence the demand for biomass fuels.[19]

If biomass fuels are ultimately treated by regulators as fully or partially carbon neutral, biomass utilization at existing coal-fired power plants could potentially play a role in reducing CO_2 emissions. At least two published papers have concluded that a five-percent reduction in CO_2 emissions from the North American electric power sector (roughly 100 Mt[20]/year) could be achieved solely by cofiring biomass with coal at existing EGUs.[21,22] Analysts

16 Megawatt hour.

17 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

18 US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

19 In July 2011, the EPA decided to temporarily defer the application of PSD and Title V permitting requirements to CO2 emissions from biogenic stationary sources while it studied whether and how to regulate such emissions. However, that decision was vacated by the US Court of Appeals for the District of Columbia Circuit (DC Circuit) in July 2013. From a regulatory standpoint, the GHG reductions that may be achievable by switching to these fuels are thus uncertain.

20 Mt is defined as millions of tons.

21 Robinson, A., Rhodes, J. S., & Keith, D. W. (2003). Assessment of Potential Carbon Dioxide Reductions Due to Biomass-Coal Cofiring in the United States. *Environ Sci Technol.* 37 (22), 5081-5089. Available at: http://pubs.acs.org/doi/pdf/10.1021/es034367q.

22 Zhang, Y., McKechnie, J., Cormier, D., Lyng, R., Mabee, W., Ogino, A., & Maclean, H. L. (2010). Life Cycle Emissions and Cost of Producing Electricity from Coal, Natural Gas, and Wood Pellets in Ontario, Canada. *Environ Sci Technol.* 44 (1), 538–544.

at McKinsey & Company offer a different estimate of the potential for reducing CO_2 emissions in the United States through biomass cofiring, putting the number at 50 Mt in the year 2030.[23] The biggest difference between these two assessments appears to be that McKinsey assumes that other, less costly CO_2 abatement measures would be implemented prior to 2030 that would lead to the retirement of large amounts of coal capacity and thus a reduced potential to cofire biomass with coal.

In the previously cited GHG Abatement Measures TSD, the EPA separately assesses the emissions reduction potential of fuel switching from coal to gas and from coal to biomass.[24] With respect to gas, the EPA concludes that emissions are reduced in direct proportion to the amount of gas cofired. Cofiring 10 percent gas with 90 percent coal will reduce GHG emissions four percent relative to firing 100 percent coal. Switching to 100 percent gas reduces GHG emissions 40 percent. WIth respect to biomass, the EPA found that stack CO_2 emissions can increase or decrease relative to firing 100 percent coal, depending on the amount and type of biomass fired, and the extent to which biomass-related GHG emissions are treated by regulators as "carbon neutral."

5. Co-Benefits

Most of the future fuel switching that will occur as a response to GHG regulations will likely involve a switch from coal (or possibly oil) to natural gas or biomass. In addition to the CO_2 emissions reductions noted above, fuel switching is likely to result in reduced emissions of other regulated air pollutants. The extent of the reductions will depend on the fuels burned before and after the fuel switch.

According to the EPA, the average natural gas-fired EGU emits just 28 percent as much NO_X as the average coal-fired EGU on an output (lb/MWh) basis, or 43 percent as much NO_x as the average oil-fired EGU, whereas emissions of particulate matter (PM), SO_2, and mercury are orders of magnitude lower for gas than for coal or oil. For repowering projects, the effects on NO_x emissions may be greater than these averages would suggest because new gas-fired EGUs are likely to be more efficient and have lower emissions than the average of gas-fired units already in place. In the GHG Abatement Measures TSD, the EPA presents information on avoided emissions of SO_2, NO_X, and $PM_{2.5}$ for a hypothetical coal plant switching to natural gas at either a ten-percent cofiring rate or at 100 percent gas.[25] For ten-percent cofiring, SO_2 emissions are reduced by 0.3 lbs/net MWh, NOx by 0.2 lbs/net MWh, and $PM_{2.5}$ by 0.02 lbs/net MWh. If 100-percent gas is fired, the reductions are 3.1 lbs/net MWh for SO_2, 2.04 lbs/net MWh for NO_x, and 0.2 lbs/net MWh for $PM_{2.5}$.

The previously cited EPRI report on cofiring natural gas with coal summarized the expected impacts of each cofiring technology on emissions of NO_x, SO_2, and CO_2. With respect to SO_2 and CO_2, EPRI reports that emissions are reduced roughly in proportion to the differences in emissions factors between natural gas and coal, and the extent to which gas is burned in lieu of coal. The effect on NO_x emissions depends on the cofiring technology used. Supplemental gas cofiring (i.e., simultaneously firing both fuels through separate burners in the boiler's primary combustion zone) can reduce NO_x emissions 10 to 15 percent, whereas the various reburn technologies, which were developed specifically for the purpose of reducing NO_X emissions, can reduce NO_X emissions by 30 to 70 percent across a range of boiler types.

In the GHG Abatement Measures TSD, the EPA does not provide avoided criteria pollutant emissions data for cofiring of biomass as it does for cofiring natural gas. Biomass fuels come in so many varieties that it is much harder and less meaningful to discuss average emissions, but the EPA notes elsewhere that in general the emissions of SO_2, NO_X, and mercury will be lower for biomass fuels than for coal, because biomass contains much less sulfur, nitrogen, and mercury than coal does. For example, Peltier reports that the repowered biomass EGU at Public Service of New Hampshire's Schiller Station emits about 75 percent less NO_X, 98 percent less SO_2, and 90 percent less mercury than before the repowering project, when the unit burned coal.[26]

When biomass and coal are cofired there is some evidence of interactive effects between the products of combustion that makes it harder to predict the resulting

23 McKinsey & Company. (2007, December). Reducing US Greenhouse Gas Emissions: How Much at What Cost? Available at: http://www.mckinsey.com/client_service/sustainability/latest_thinking/reducing_us_greenhouse_gas_emissions.

24 Supra footnote 2.

25 Ibid.

26 Peltier, R. (2007). PSNH's Northern Wood Power project repowers coal-fired plant with new fluidized-bed combustor. POWER. Available at: http://www.powermag.com/psnhs-northern-wood-power-project-repowers-coal-fired-plant-with-new-fluidized-bed-combustor/

impact on non-GHG emissions. The literature on this subject, as summarized by Robinson et al, consistently reports SO_2 emissions reductions, but there are some indications that a 10-percent/90-percent cofiring of biomass/coal (for example) can produce a greater than ten-percent reduction in SO_2 emissions. The majority of studies also report modest NO_X reductions, but some studies report no NO_X benefit and one study found that biomass reburning in a secondary combustion zone can reduce NO_X emissions by 60 percent.[27] Aerts & Ragland, on the other hand, reported the results of one test in which cofiring 10 percent switchgrass with 90 percent coal reduced NO_x emissions by 17 to 31 percent.[28]

The full range of co-benefits that can be realized through fuel switching is summarized in Table 9-4. In this table, "utility system" benefits are those that are shared between the owners of power plants and their customers.

6. Costs and Cost-Effectiveness

In virtually all cases, fuel switching will increase operations and maintenance (O&M) costs above the status quo, or require a capital investment, or both. Where neither type of cost increase is necessary, fuel switching will usually have already occurred for economic reasons. In the context of mandatory GHG regulations for existing sources, the relevant question will not be whether fuel switching increases capital or operating costs but whether it costs less than other compliance options. This question can only be answered on a case-by-case basis for each EGU, but some useful general observations can be gleaned from the literature.

The previously cited NYSERDA report on CO_2 emissions reductions in the RGGI states does not delineate the costs of fuel switching as an emissions reduction strategy, but it does offer a few insights into the economic drivers for fuel switching. NYSERDA found that switching from petroleum and coal generation to natural gas "was caused in large part by the decrease in natural gas prices relative to petroleum and coal prices... Natural gas prices decreased by 42 percent from 2005 to 2009, while both petroleum and coal prices increased. Through 2005, natural gas prices were generally higher than No. 6 oil prices (dollars per MMBTU); beginning in 2006, natural gas prices have been lower than No. 6 oil prices... The price gap between US natural gas and coal decreased by 61 percent, from \$6.72 per MMBTU in 2005 to \$2.62 per MMBTU in 2009... The changing fuel price landscape has resulted in dual fuel units

Table 9-4

Types of Co-Benefits Potentially Associated With Fuel Switching

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_x	Yes
SO_2	Yes
PM	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Yes; could be positive or negative
Other	

27 Robinson et al., at supra footnote 21.

28 Aerts, D. & Ragland, K. (1997). *Switchgrass production for biomass.* Research Brief No. 51: University of Wisconsin, Madison, WI. Available at: http://www.cias.wisc.edu/switch-grass-production-for-biomass/.

burning natural gas rather than oil."[29]

The observations in the NYSERDA report are likely to hold true for multi-fuel facilities everywhere, although the fuel price differentials may vary geographically. In some cases, other operational cost impacts of fuel switching, such as reduced ash handling costs when gas use displaces coal, may factor into compliance decisions. Over the longer term, maintenance costs may vary somewhat based on how much of each type of fuel is used, and those costs could affect compliance decisions as well.

It is more difficult to assess costs and cost-effectiveness when cofiring or repowering strategies are used, but this question has been tackled head-on in some of the relevant literature. With respect to cofiring coal and natural gas, the previously cited EPRI report examined case studies of actual cofired EGUs.[30] In several of these cases, supplemental gas cofiring was used either to allow use of an alternate coal or to reduce fly ash carbon levels. EPRI found that in these applications, "gas cofiring improved the combustion characteristics of an alternate coal or reduced the existing carbon levels in the fly ash, but was not sufficient to produce a payback. Either carbon in the fly ash remained above three percent, making it unsalable as a high-priced cement additive, or alternate coal combustion characteristics were not improved sufficiently to provide added boiler flexibility." However, EPRI also found examples where cofiring with gas corrected problems that had led to a derate of the EGU. Eliminating the derate made cofiring a cost-effective choice. Finally, EPRI found that gas re-burn technologies were cost-effective means of reducing NO_x emissions, relative to installing pollution control devices, and supplemental gas cofiring was similarly cost-effective for reducing NO_x in some but not all cases. More recent studies from the engineering firm Black & Veatch indicate that capital costs for cofiring gas with coal can range from $10 to $100 per kilowatt (kW).[31]

Robinson et al offer a number of insights into the economics of cofiring biomass with coal.[32] Their analysis assigns a 5- to 15-percent premium on the nonfuel O&M costs for biomass fuels relative to coal, depending on the cofire rate. Biomass fuel costs are much more variable. Fuel costs can be zero or even negative in cases where onsite or local biomass sources exist, especially if the biomass fuel is a waste-derived fuel that would otherwise have to be landfilled. But in general, they found that the fuel costs of biomass on a BTU basis can be up to four times the cost of coal. Finally, in terms of the capital costs necessary to enable cofiring, their model assumes that biomass can be cofired at up to two percent of total energy input without any modifications to the coal handling and combustion systems. Higher rates of biomass cofiring require a capital investment on the order of $50/kW to $300/kW, depending on the cofire rate. Compiling all of these data along with the potential for cofiring at existing US coal EGUs, the authors found that cofiring with biomass could reduce CO_2 emissions from the coal-fired electricity generation sector by ten percent at a carbon price of about $50 per metric ton. The previously cited analysis by McKinsey & Company cited a lower CO_2 abatement cost, on the order of about $30 per metric ton.[33]

The last fuel switching option to consider is repowering. In a recent study of options for repowering existing steam plants with combined-cycle technology, EPRI found that repowering could cost about 20 percent less than building a completely new combined-cycle plant on a capacity ($/kW) basis, and 5 percent less on a cost-of-electricity ($/MWh) basis.[34] Other analysts have placed the cost of converting an existing coal-fired boiler to natural gas at just 15 to 30 percent of the cost of a new gas boiler.[35] Black & Veatch analysts estimate that the capital costs of repowering from coal to gas range between $100/kW and $250/kW, or higher if a new combined-cycle gas turbine is installed.[36] These costs compare quite favorably to the EIA's estimated cost for a new conventional natural gas combustion turbine of $973/kW or a new conventional natural gas combined-

29 Supra footnote 15.

30 Supra footnote 12.

31 Nowling, U. (2013, October 1). Utility Options for Leveraging Natural Gas. *POWER*. Available at: http://www.powermag.com/utility-options-for-leveraging-natural-gas/?pagenum=1.

32 Robinson et al., at supra footnote 21.

33 Supra footnote 23.

34 EPRI. (2012, August 8). *Repowering Fossil Steam Plants with Gas Turbines and Heat Recovery Steam Generators: Design Considerations, Economics, and Lessons Learned.*

35 Ingraham, J., Marshall, J., Flanagan, R. (2014, March 1). Practical Considerations for Converting Industrial Coal Boilers to Natural Gas. *POWER*. Available at: http://www.powermag.com/practical-considerations-for-converting-industrial-coal-boilers-to-natural-gas/.

36 Supra footnote 31.

cycle unit of $917/kW.[37]

A 2012 case study analysis by Reinhart et al considered the relative costs of five different strategies for reducing emissions from a hypothetical coal-fired power plant.[38] The options considered included full repowering of the existing boiler and turbine to natural gas; modifications of the existing equipment to allow cofiring of natural gas with coal; installation of emissions control equipment without other changes; repowering the existing steam turbine to operate in combined-cycle mode; and full replacement of the existing unit with a combined-cycle natural gas unit. The authors concluded that the least-cost option varied depending on assumptions about future fuel prices, the service life of the unit, and future capacity factors of the unit. Modifying the unit to allow cofiring was not the least-cost option in any of the examined scenarios, but each of the other options was least-cost in at least one scenario. The conclusion one can draw from this paper is that the relative merits of different fuel-switching options depend in part on variables that are generally location- and case-specific.

In the GHG Abatement Measures TSD, the EPA published its own review of the costs and cost-effectiveness of repowering an existing coal boiler to be able to fire gas or biomass.[39] For a typical 500-MW pulverized coal boiler, total capital costs for repowering to gas were estimated to be $237/kW, which would add about $5/MWh to levelized costs of generation. The EPA further estimated that fixed O&M costs would decline by 33 percent, whereas variable O&M costs would drop 25 percent owing to reduced waste disposal, reduced auxiliary power requirement, and miscellaneous other costs. Fuel costs, on the other hand, were expected to double – adding $30/MWh to levelized costs. Putting these factors together, the EPA estimated that the average cost of repowering to gas would be $83/metric ton of CO_2 reduction for 100-percent gas firing, or $150/metric ton for ten-percent gas cofiring.

The EPA estimated that the capital cost associated with adding ten-percent biomass cofiring capability to a 500-MW coal unit would be $20/kW. Fixed O&M costs in this case were estimated to increase by ten percent, while variable O&M costs remained constant. The EPA found that the fuel cost of biomass is highly site-specific. Putting these factors together, the EPA estimated that the cost per metric ton of CO_2 reduction would likely fall between $30 and $80 for biomass cofiring, if the biomass-related emissions were treated as carbon-neutral.

Although the EPA acknowledged in the GHG Abatement Measures TSD that some coal plant owners are engaging in repowering projects, the agency concluded that this kind of fuel switching will be on average more expensive than other available options, such as constructing a new natural gas combined-cycle unit. Because gas and biomass cofiring options were found to be relatively expensive when national average cost data were used, the EPA declined to include fuel switching as part of the "best system of emissions reduction" in its proposed emissions guidelines.

7. Other Considerations

Where physical modifications of a power plant are necessary to facilitate fuel switching, the owner of the power plant will generally not want to make such modifications unless he or she has a reasonable expectation that the capital costs of the project can be recovered from the sale of energy to wholesale markets, a purchasing utility, or retail ratepayers. (Exceptions to this general rule may exist where the owner has a compliance obligation and less costly options are not feasible.) In the case of a power plant owned by an investor-owned utility, the utility will further expect to realize a profit for shareholders. This concern with cost recovery (and profit) is likely to be even more pronounced in regions of the country that have adopted competitive wholesale markets. In those regions, the owners of power plants have no guarantee that their assets will clear the energy market over any given operating period, be dispatched, and earn revenue. Thus, they have no guarantee that the considerable costs associated with repowering an EGU, or even the lesser costs of modifying an EGU to allow cofiring of different fuels, will be recovered. Still, where the owner sees a reasonable expectation of reward to accompany this risk, fuel switching may be an attractive option.

One potential regulatory issue that is often cited by regulated entities as a concern is the possibility that a repowering project could trigger federal New Source Review, PSD, or New Source Performance Standard (NSPS)

37 US EIA. (2013, April). *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Available at: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

38 Reinhart, B., Shah, A., Dittus, M., Nowling, L., & Slettehaugh, B. (2012). *A Case Study on Coal to Natural Gas Fuel Switch.* Retrieved from the Black & Veatch website: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

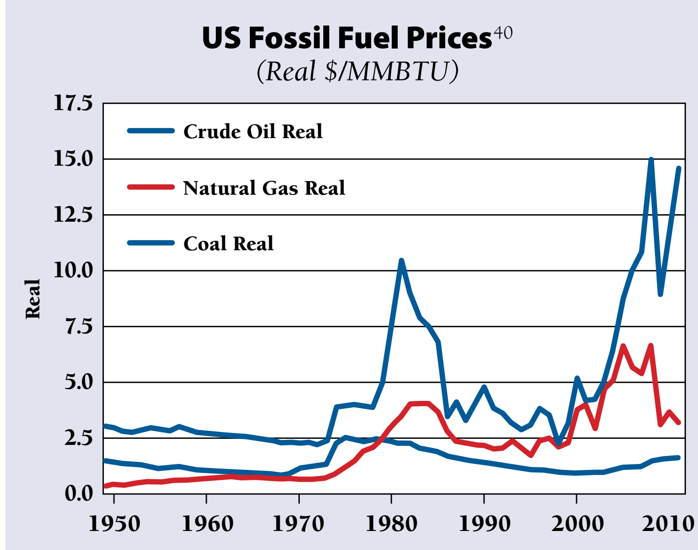
39 Supra footnote 2.

requirements. Satisfying New Source Review, PSD, or NSPS requirements could require the installation of new pollution control devices and add considerably to the cost of such a project, perhaps to the point at which it is no longer economically justifiable to the source owner. But in general, repowering projects will reduce not just CO_2 emissions rates (per MWh), but also the emissions rates of other regulated air pollutants, and this potential problem for source owners is unlikely to materialize. Exceptions may arise in which a repowering project opens the door to greater utilization of the EGU. This could happen, for example, if the repowered unit will have significantly lower operating costs than the existing EGU. If the unit then increases its annual hours of operation, its annual emissions of one or more pollutants could conceivably increase by an amount large enough to trigger other regulations. There may also be cases in which the capital cost of a repowering project exceeds 50 percent of the capital cost that would be required to construct a comparable new facility, thus meeting the Clean Air Act definition of "reconstruction" and triggering NSPS requirements.

The most obvious opportunities to reduce emissions through fuel switching are found at power plants that burn coal or oil as a primary fuel. However, the availability of firm natural gas pipeline capacity may in some cases create limitations on the potential for fuel switching. The most obvious limitation arises where a power plant is not connected to a natural gas pipeline. Extending a pipeline to reach such a power plant requires a significant capital investment, over and above any costs of modifying the power plant itself, as well as a lengthy permitting and construction process. But even where the power plant is already connected to a gas pipeline, there may be limitations. The capacity of gas pipelines relative to peak customer demand varies regionally. During a prolonged cold spell in the winter months of 2014, many power plants in the Northeastern United States found that they could not obtain gas because they did not have firm delivery contracts, and those that did have firm contracts were using nearly all of the existing pipeline capacity. This is not an insurmountable problem; it can be alleviated by adding gas pipeline capacity or by changing contract terms. But it does potentially limit the ability of some sources to reduce CO_2 emissions through fuel switching.

Historically, oil and natural gas prices have been more volatile than coal prices, as shown in Figure 9-3. Owners of coal-fired generation may be reluctant to depend on fuel switching as the means to meet mandatory CO_2 emissions limitations because of the perception, backed by history, that using other fossil fuels increases uncertainty about future fuel costs. Recent advances in production techniques (hydraulic fracturing, principally) have reduced short-term domestic gas prices considerably, but it remains to be seen if these techniques will have an impact on the long-term volatility of prices.

Figure 9-3



The potential for emissions reductions described earlier in this chapter assumes that the operating capabilities of an EGU will not be affected by fuel switching. In practice, this may not always be the case. The capacity of an EGU can be uprated or derated depending on the heat content of the fuels used, if the rate at which the fuels are consumed remains constant. So, for example, consider the case in which a boiler burns a coal with a high input emissions factor at some maximum rate based on the design of the fuel delivery system and burners. If this coal is then blended with a different rank of coal that has a lower heating value, but the maximum rate that the blended fuel is consumed remains unchanged, then the capacity of the EGU will decrease. Any owner of an EGU will be concerned about a derate of its capacity.

Any fuel switching project that requires an EGU to go offline for an extended period of time may raise concerns about reliability impacts. The likelihood of such impacts will vary with the size (i.e., capacity) of the EGU, the duration of the scheduled downtime, and the amount of

40 US EIA. (2012, September). *Annual Energy Review 2011*. Available at: http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

excess capacity available to meet load during the scheduled downtime.

Power plants that have not previously utilized biomass or biogas fuels may encounter significant challenges in securing reliable fuel supplies and a supply chain that can reliably deliver the fuel. This can present a classic chicken-and-egg dilemma, wherein generators will not switch fuels until they are certain a reliable fuel supply and supply chain exists, but a supply chain will not materialize until there is sufficient demand for the fuel. Onsite storage of solid biomass fuels can also pose problems in terms of storage space, fire risks, or fugitive dust concerns. These same concerns are present at coal-fired power plants, so they are not novel issues when it comes to fuel switching to biomass. Just as there are techniques to deal with these issues at coal plants, there are similar techniques to deal with them at biomass plants.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on fuel switching:

- Black, S., & Bielunis, D. (2013, August). *Challenges when Converting Coal-Fired Boilers to Natural Gas.* Babcock Power Inc. Available at: http://www.babcockpower.com/pdf/RPI-TP-0232.pdf.
- EPRI. (2000, August). *Gas Cofiring Assessment for Coal Fired Utility Boilers.* Palo Alto, CA.
- EPRI. (2012, August 8). *Repowering Fossil Steam Plants with Gas Turbines and Heat Recovery Steam Generators: Design Considerations, Economics, and Lessons Learned.*
- Nicholls, D., & Zerbe, J. (2012, August). *Cofiring Biomass and Coal for Fossil Fuel Reduction and Other Benefits—Status of North American Facilities in 2010.* General Technical Report PNW-GTR-867. US Department of Agriculture, Forest Service, Pacific Northwest Research Station.
- US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.
- US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

9. Summary

Fuel switching in its various forms offers a proven emissions reduction strategy that will be feasible to a lesser or greater extent for many covered sources. Literally thousands of EGUs in the United States already have the capability to fire multiple fuels, and many more could be candidates for a repowering project. The primary limitation on this strategy is not technical but economic. Most EGUs that are not already using low-emitting fuels as a primary energy source are using higher-emitting fuels for economic reasons. Fuel switching could increase the operating costs, and possibly add capital costs, for these sources. However, the underlying economics will change when new mandatory CO_2 emissions limits are in place. Generation owners will then want to reconsider the relative costs of different fuels and determine if fuel switching is their best compliance option.