BENCHMARKING AIR EMISSIONS

OF THE 100 LARGEST ELECTRIC POWER PRODUCERS IN THE UNITED STATES

JULY 2016

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Acknowledgments

This report is the product of a collaborative effort among Bank of America, Calpine, Entergy, Exelon, Ceres, and the Natural Resources Defense Council (NRDC). The project partners would like to acknowledge and thank the following people who made this report possible. Ceres' participation in this effort was made possible by a grant from the Bank of America Charitable Foundation.

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When citing this report, the following format is recommended:

M. J. Bradley & Associates. (2016). *Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States.*

Preface

The 2016 Benchmarking report is the twelfth collaborative effort highlighting environmental performance and progress in the nation's electric power sector. The Benchmarking series began in 1997 and uses publicly reported data to compare the emissions performance of the 100 largest power producers in the United States. The current report is based on 2014 generation and emissions data.

Data on U.S. power plant generation and air emissions are available to the public through several databases maintained by state and federal agencies. Publicly- and privately-owned electric generating companies are required to report fuel and generation data to the U.S. Energy Information Administration (EIA). Most power producers are also required to report air pollutant emissions data to the U.S. Environmental Protection Agency (EPA). These data are reported and recorded at the boiler, generator, or plant level, and must be combined and presented so that company-level comparisons can be made across the industry.

The Benchmarking report facilitates the comparison of emissions performance by combining generation and fuel consumption data compiled by EIA with emissions data on sulfur dioxide (SO_2), nitrogen oxides (NOx), carbon dioxide (CO_2) and mercury (Hg) compiled by EPA; error checking the data; and presenting emissions information for the nation's 100 largest power producers in a graphic format that aids in understanding and evaluating the data. The report is intended for a wide audience, including electric industry executives, environmental advocates, financial analysts, investors, journalists, power plant managers, and public policymakers.

The report is available in PDF format on the Internet at http://www.ceres.org and http://www.nrdc.org. Plant and company level data used in this report are available on the Internet at http://www.mjbradley.com.

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Executive Summary

This report examines and compares the stack air pollutant emissions of the 100 largest power producers in the United States based on their 2014 generation, plant ownership, and emissions data. Table ES.1 lists the 100 largest power producers featured in this report ranked by their total electricity generation from fossil fuel, nuclear, and renewable energy facilities. These producers include public and private entities[1] (collectively referred to as "companies" or "producers" in this report) that own roughly 2,900 power plants and account for 85 percent of reported electric generation and 87 percent of the industry's reported emissions.

The report focuses on four power plant pollutants for which public emissions data are available: sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury (Hg), and carbon dioxide (CO_2). These pollutants are associated with significant environmental and public health problems, including acid deposition, mercury deposition, nitrogen deposition, global warming, smog, regional haze, and fine particle air pollution, which

TABLE ES.1

100 Largest Electric Power Producers in the U.S. (in order of 2014 electric generation)

RANK	PRODUCER NAME	2014 MWh (millions)	RANK	PRODUCER NAME	2014 MWh (millions)	RANK	PRODUCER NAME	2014 MWh (millions)	RANK	PRODUCER NAME	2014 MWh (millions)
1	Duke	245.0	26	Energy Capital Partners	28.6	51	Tenaska	14.6	76	BP	10.0
2	Southern	190.9	27	Salt River Project	27.9	52	JEA	14.2	77	Energy Northwest	9.9
3	NextEra Energy	183.0	28	Pinnacle West	27.6	53	IDACORP	13.8	78	CLECO	9.9
4	Exelon	178.0	29	New York Power Authority	25.7	54	Rockland Capital	13.6	79	Integrys	9.7
5	AEP	162.9	30	Westar	25.3	55	Los Angeles City	13.5	80	Brookfield	9.6
6	Tennessee Valley Authority	142.9	31	General Electric	25.2	56	Edison International	13.3	81	ALLETE	9.5
7	NRG	136.7	32	Great Plains Energy	24.9	57	Tri-State	12.8	82	El Paso Electric	9.5
8	Entergy	130.3	33	Wisconsin Energy	24.1	58	Occidental	12.5	83	PUD No 1 of Chelan County	9.5
9	Berkshire Hathaway Energy	118.9	34	SCANA	23.4	59	Intermountain Power Agency	12.4	84	Buckeye Power	9.4
10	Calpine	101.8	35	Santee Cooper	23.1	60	Riverstone	12.1	85	Fortis Inc.	8.8
11	FirstEnergy	95.4	36	OGE	22.8	61	Dow Chemical	12.0	86	Entegra Power	8.8
12	Dominion	92.9	37	Oglethorpe	22.3	62	Municipal Elec. Auth. of GA	11.9	87	E.ON	8.8
13	PPL	86.6	38	CMS Energy	21.8	63	Puget Holdings	11.6	88	Brazos Electric Power Coop	8.8
14	US Corps of Engineers	73.3	39	EDF	21.7	64	Portland General Electric	11.1	89	PUD No 2 of Grant County	8.4
15	Xcel	73.2	40	LS Power	19.8	65	Exxon Mobil	11.1	90	Austin Energy	8.3
16	Energy Future Holdings	68.4	41	TECO	18.7	66	Arkansas Electric Coop	11.0	91	The Carlyle Group	7.9
17	Dynegy	58.7	42	Alliant Energy	18.6	67	Energy Investors Funds	10.8	92	TransCanada	7.9
18	PSEG	54.1	43	Basin Electric Power Coop	18.4	68	PNM Resources	10.8	93	Big Rivers Electric	7.7
19	Ameren	43.6	44	ArcLight Capital	16.8	69	Invenergy	10.8	94	Avista	7.3
20	DTE Energy	42.8	45	NE Public Power District	16.5	70	Seminole Electric Coop	10.7	95	Hoosier Energy	7.3
21	US Bureau of Reclamation	42.1	46	Omaha Public Power District	16.2	71	EDP	10.6	96	TransAlta	7.2
22	AES	37.6	47	Iberdrola	15.9	72	Great River Energy	10.5	97	Seattle City Light	7.1
23	GDF Suez	32.7	48	NC Public Power	15.5	73	Lower CO River Authority	10.3	98	International Paper	6.9
24	San Antonio City	29.2	49	Associated Electric Coop	15.0	74	Sempra	10.2	99	NorthWestern Energy	6.9
25	PG&E	29.0	50	NiSource	14.9	75	East Kentucky Power Coop	10.2	100	Sacramento Municipal Util Dist	6.8

can lead to asthma and other respiratory illnesses. The report benchmarks, or ranks, each company's absolute emissions and its emission rate (determined by dividing emissions by electricity produced) for each pollutant against the emissions of the other companies.

Major Findings

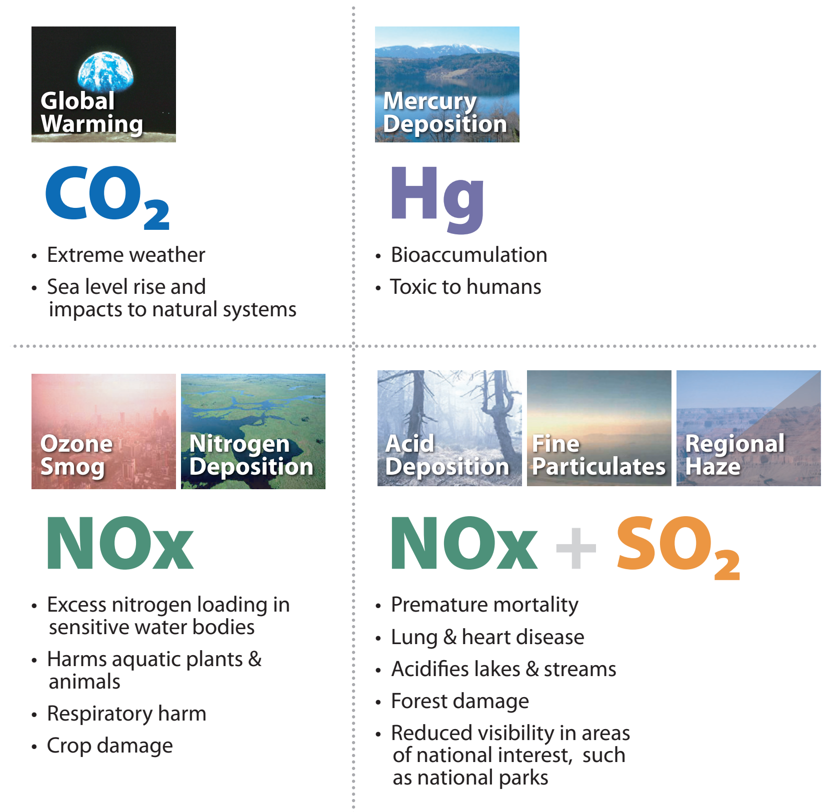
Electricity Industry Emission Trends

Since 1990, power plant emissions of SO_2, NOx, and Hg have decreased while CO_2 emissions have increased.

- In 2014, power plant SO_2 and NOx emissions were 80 percent and 75 percent lower, respectively, than they were in 1990 when Congress passed major amendments to the Clean Air Act.
- Power plant CO_2 emissions were 14 percent higher in 2014 compared to 1990. However, emissions have decreased in recent years, dropping 12 percent between 2008 and 2014. Some of the factors driving this trend include energy efficiency improvements and displacement of coal generation by natural gas and renewable energy.
- In 2014, power plant SO_2, NOx, and CO_2 emissions rates were 85 percent, 81 percent, and 16 percent lower, respectively, than they were in 1990.
- Mercury emissions from coal power plants have decreased 55 percent since 2000, with the mercury emission rate decreasing by 44 percent. Mercury emissions will continue to decline as the first federal limits on mercury and other hazardous pollutants from coal-fired power plants went into effect in 2015.
- Since 2000, emissions from all four pollutants have dropped while total generation and gross domestic product have increased.

FIGURE ES. 1

Environmental Concerns Associated with Power Plant Emissions



Overall Emissions from Electricity

- In 2014, power plants were responsible for 62 percent of SO_2 emissions, 14 percent of NOx emissions, 58 percent of mercury emissions (among sources reporting to EPA's Toxic Release Inventory), and 37 percent of all CO_2 emissions in the U.S.
- The electric industry accounts for more CO_2 emissions than any other sector, including the transportation and industrial sectors.

Air Pollution Rankings and Comparisons

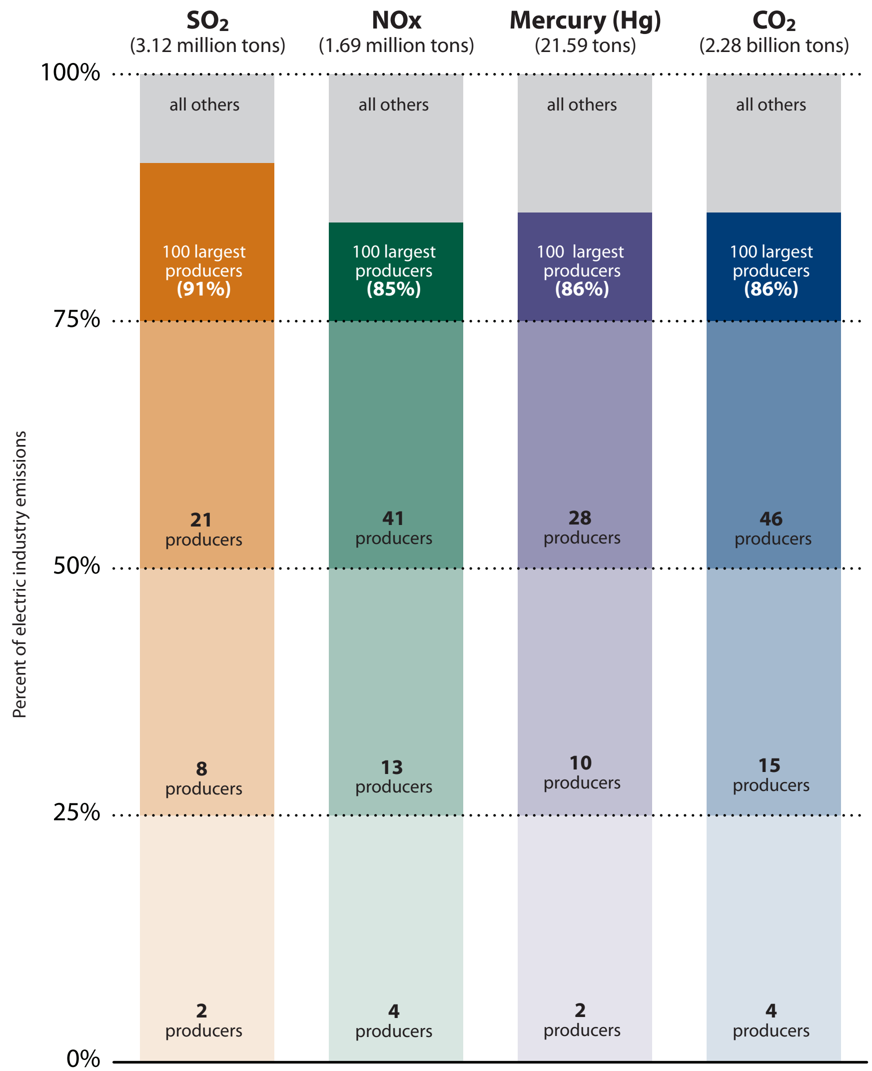
The 100 largest power producers generated 85 percent of electric power in the U.S. in 2014. The 100 largest producers generated 97 percent of all nuclear power, 89 percent of all coal-fired power, 88 percent of all hydroelectric power, 80 percent of all natural gas-fired power, and 72 percent of all non-hydroelectric renewable power.

Air pollution emissions from power plants are highly concentrated among a small number of producers. For example, a quarter of the electric power industry's SO_2 and CO_2 emissions are emitted by just two and four of the top 100 producers, respectively. Figure ES.2 summarizes the distribution of emissions among electric power producers.

Electric power producers' emission levels and emission rates vary significantly due to the amount of power produced, the efficiency of the technology used in producing the power, the fuel used to generate the power, and installed pollution controls.

FIGURE ES.2

Concentration of Air Emissions among All Electric Power Producers



In 2014, total generation among the 100 largest power producers ranged from 6.8 million to 245 million megawatt hours. Among the companies reporting fossil fuel use:

- SO_2 emissions ranged from 0.2 to 320,894 tons, and SO_2 emission rates ranged from 0.0001 to 9.9 pounds per megawatt hour;
- NOx emissions ranged from 12 to 111,446 tons, and NOx emission rates ranged from 0.002 to 3.8 pounds per megawatt hour;
- CO_2 emissions ranged from 0.49 to 141.4 million tons, and CO_2 emission rates ranged from 10 to 2,294 pounds per megawatt hour;
- Mercury emissions from producers with coal plants ranged from less than 1 to 4,448 pounds, and mercury emission rates ranged from 0.0003 to 0.081 pound per gigawatt hour (GWh; a GWh is 1,000 megawatt hours).

Electric Industry Overview

Electric power production is essential to the growth and operation of the U.S. economy. The availability, reliability, and price of electricity have significant impacts on national economic output, energy security and quality of life. At the same time, the production of electricity from fossil fuels results in air pollution emissions that affect both public health and the environment.

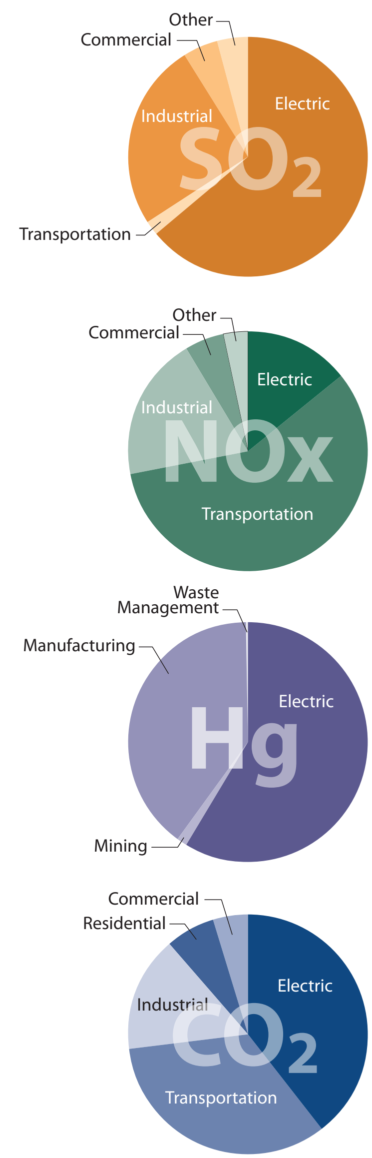
This report focuses on four power plant pollutants for which public emissions data are available: sulfur dioxide (SO_2), nitrogen oxides (NOx), mercury (Hg), and carbon dioxide (CO_2). Collectively, power plants are responsible for about 62 percent of U.S. SO_2 emissions, 14 percent of NOx emissions, 58 percent of mercury emissions (among sources reporting to EPA's Toxics Release Inventory), and 37 percent of CO_2 emissions in the U.S. The electric power industry accounts for more CO_2 emissions than any other sector, including the transportation and industrial sectors.

SO_2 and NOx emissions from power plants both contribute to acid rain, regional haze, and fine particle air pollution. Acid rain damages trees and crops, acidifying soils, lakes, and streams. Fine particle air pollution can adversely affect the heart and lungs through inhalation. Exposure to fine particle air pollution is linked to premature death and illness from respiratory disease and other ailments, particularly in children and the elderly. Regional haze impairs visibility, including at national parks. NOx emissions are also associated with nitrogen deposition and ground-level ozone. Nitrogen deposition can impair water quality and degrade soil, harming trees, crops, and aquatic ecosystems. Ground-level ozone has also been linked to serious respiratory problems.

Mercury emissions from power plants deposited to lakes, ponds, and oceans are converted by certain microorganisms to a highly toxic form of the chemical known as methylmercury. Methylmercury then accumulates in fish and shellfish, as well as in birds and mammals that feed on fish. Humans are exposed to mercury when they eat contaminated fish. Exposure to methlymercury is detrimental to the development of fetuses and young children.

FIGURE 1

U.S. Electric Industry Contribution to Total Emissions (2014)

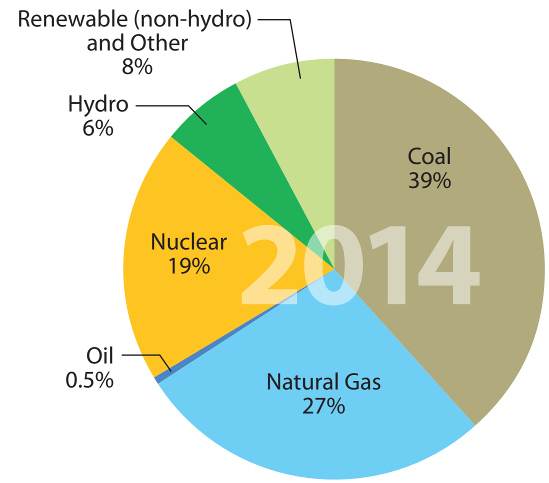


CO_2 is the most prevalent of anthropogenic (or human caused) greenhouse gas emissions. Greenhouse gases (or global warming pollutants) trap heat in the atmosphere and at elevated concentrations lead to global climate change. Climate change threatens public health due to more severe heat waves, exacerbation of ground-level ozone formation, and increases in extreme weather, such as floods and droughts. Climate change may also threaten key natural resources, disrupting sensitive ecosystems, increasing the intensity and frequency of wildfires, causing insect outbreaks, and impacting water and food availability. Conflicts, mass migrations, health impacts, or environmental stresses in other parts of the world could also raise national security concerns for the United States.

Because of their associated public health and environmental risks, SO_2, NOx, mercury, and greenhouse gases are regulated under the Clean Air Act.

FIGURE 2

U.S. Electricity Generation by Fuel Type (2014)



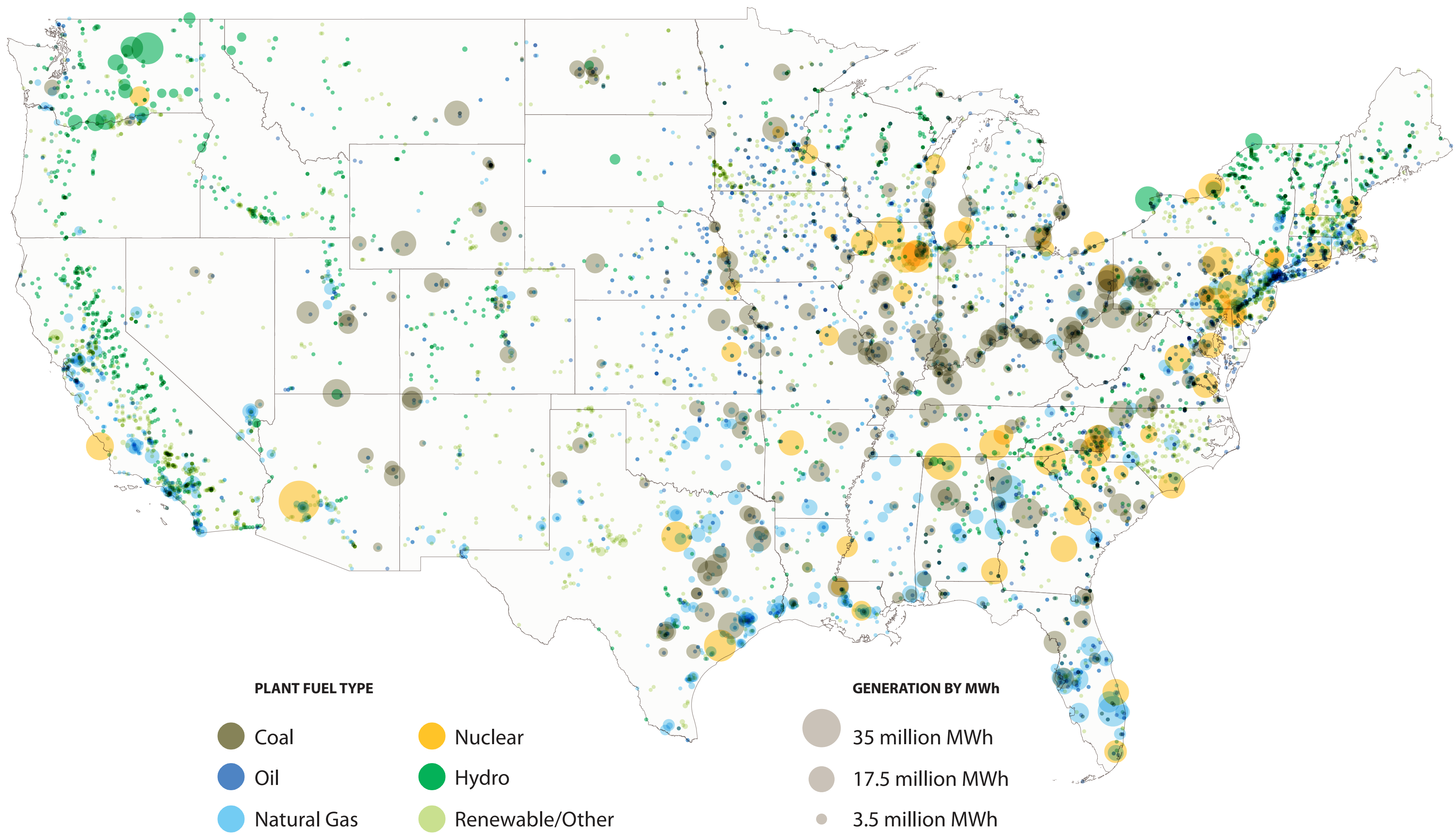
Sources of Power

Over 7,100 power plants generate electricity in the U.S. In 2014, these plants generated more than 4 billion megawatt hours of electricity. About 67 percent of this power was produced by burning fossil fuels (coal, natural gas, and oil) resulting in the release of SO_2, NOx, mercury, and CO_2 into the air. Coal accounted for about 39 percent of total power production, natural gas accounted for 27 percent, and oil's contribution was negligible, less than half a percentage point. Nuclear power, the largest non-fossil fuel energy source, generated 19 percent of U.S. electric power and 62 percent of all zero-emission generation. Hydroelectricity accounted for 6 percent of total power production and non-hydroelectric renewables (such as wind turbines and solar photovoltaic cells) accounted for 5 percent. A variety of other fuel sources comprised the remaining 2 percent of generation.

Coal-fired power plants are located across the nation, most predominantly in the midwestern and southeastern parts of the country, with the heaviest concentrations of coal plants located along the Ohio and Mississippi Rivers. Natural gas plants are generally smaller than coal plants and occur throughout the country, with significant recent capacity additions in states with access to shale gas resources. Most large nuclear plants are located in eastern and upper-midwestern states, and most large hydroelectric facilities are in northwestern states.

FIGURE 3

Location and Relative Size of U.S. Power Plants by Fuel Type



SOURCE: MJB&A ANALYSIS; VELOCITY SUITE; U.S. ENERGY INFORMATION ADMINISTRATION: FORM EIA-923 (2014).

FIGURE 4

U.S. Electric Generating Capacity by In Service Year

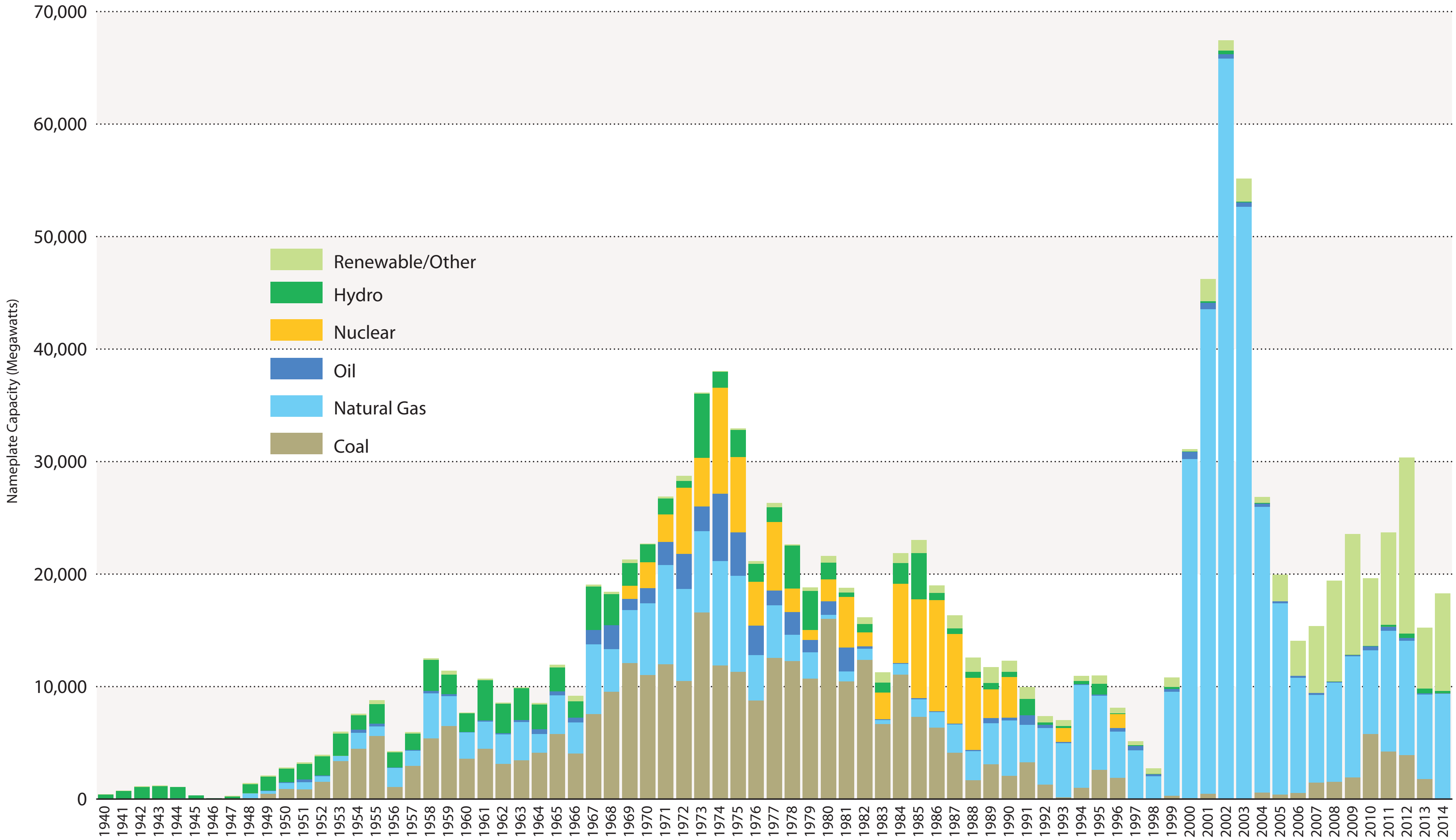


Figure 3 plots the locations of the nation's major power plants, sized according to their electricity production in 2014 and colored based on their primary fuel type.

Power plant development in the U.S. has occurred in cycles with a dramatic spike in natural gas-fired power plant construction from 2000-2005. Most coal-fired power plants were built before 1980. There was a wave of nuclear plant construction from the late 1960s to about 1990. Since 2005, some new coal-fired plants have come on-line, but most new capacity has been either natural gas fired or renewable energy. Figure 4 presents the in-service year and fuel type of the existing electric generating fleet in the U.S.

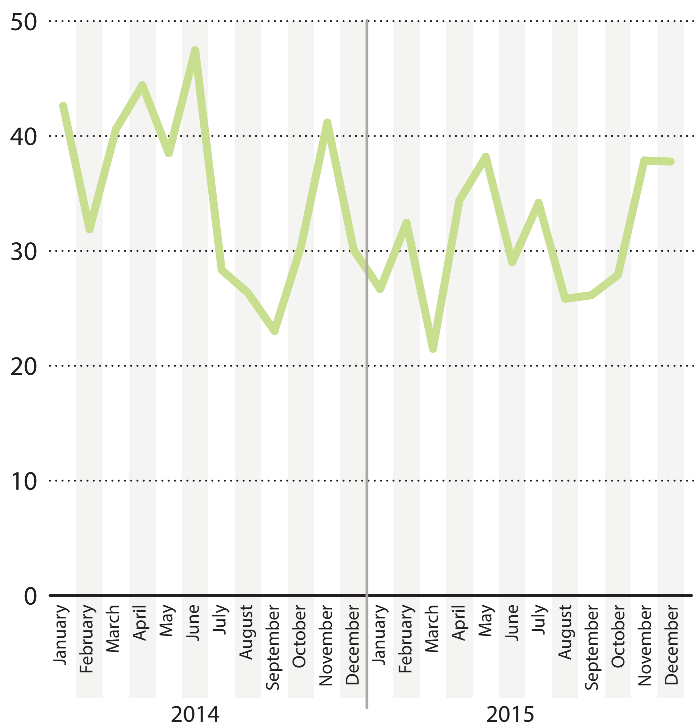
State of the Market: U.S. Power Sector in the Midst of a Deep Structural Transformation

On December 20, 2015, wind resources provided about 40 percent of Texas's total electricity needs.[3] On that day the wind turbines achieved capacity factor levels that are usually associated with nuclear and fossil-fired baseload generators: nearly 90 percent during several hours and more than 60 percent on average over the course of the day. Texas added over 3 GW of wind resources in 2015 alone, taking the total to 16 GW, or nearly 50 percent of the state's off-peak demand.[4] As the amount of wind capacity increases, so does the likelihood that during hours of low demand output from baseload generators and wind would exceed total system load. Partially as a result, wholesale power prices in Texas often remain at or near zero for several hours.[5] At other times output from the same wind turbines can plummet depending on wind conditions. Consequently, in the past two years average monthly capacity factors of wind resources in Texas have ranged from 21 to 47 percent (see Figure 5). This has implications for the economics of the power sector.

Texas boasts more wind installations than any other state in the country. And its electricity grid is more or less an island, limiting the state's ability to ship electricity to other markets when there is excess supply.

FIGURE 5

Wind Turbine Capacity Factors in Texas
(% average monthly)



Consequently, such dramatic conditions are more pronounced in Texas than elsewhere. But the events in Texas shine a spotlight on the changes looming over the U.S. power sector at large. Renewable sources of energy are beginning to play a bigger role, while overall demand for electricity has been flat or declining. And historically low natural gas prices, combined with these changes, are driving unprecedented change in the U.S. electric sector.

Just a decade ago output from fledgling wind and solar projects was barely a rounding error, natural gas prices routinely exceeded $10 per MMBtu (nearly five times the levels in 2015),[6] and coal was the undisputed king of power generation, accounting for more than 50 percent of total U.S. output, more than twice as much as natural gas.[7] Much has changed since then. In 2015, U.S. natural gas- and coal-fired generators produced virtually equal amounts of electricity, output from wind and solar installations came close to rivaling total hydroelectric generation, and natural gas prices plumbed depths not seen since 1999.[8]

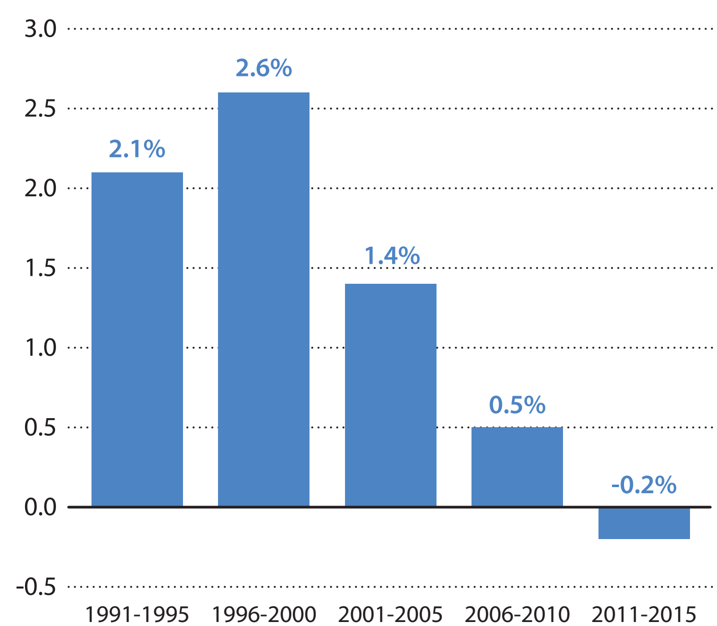
Lots of New Supply, Little New Demand

The impact of these supply-side changes on the electric sector would be a good bit less dramatic if overall U.S. electricity demand was still growing briskly. In such a world new output–renewable energy and natural-gas fired generation–would go toward filling a demand gap instead of displacing existing generation. But demand growth is headed in the opposite direction (see Figure 6). Electricity consumption actually declined at an annual average rate of 0.2 percent in the five years to 2015.[9] Growth rates have been tepid for some time: in every five-year period since 1996 they have declined.[10] Consequently, as output from low-carbon resources grow they end up battling with existing generators, including other existing low carbon resources, for a slice of an ever-shrinking pie.

This decline in electricity consumption is mainly due to lackluster demand from the industrial sector and little to no growth in the residential and commercial sectors. Electrification of transport may, in the future, drive overall electricity consumption higher. But for now increased deployment of distributed generation, growing investments in energy efficiency programs, slower growth in a mature U.S. economy, and

FIGURE 6

U.S. Electricity Consumption Growth Rates
(% average annual growth rate)



global macroeconomic fundamentals are all contributing to dampen demand for grid electricity. For example, the industrial sector has suffered from deindustrializing regional economies and, more recently, from a strong dollar. The U.S. dollar has appreciated more than 20 percent[11] on a trade-weighted basis in the last five years. A rising currency makes U.S. exports less competitive leading to lower electricity consumption. Faltering emerging market economies, which import U.S. capital goods and industrial supplies,[12] have further exacerbated the anemic demand from the U.S. industrial sector. At the same time, end-use efficiency gains[13] have contributed to lower electricity consumption in the residential and commercial categories. For example, reduction in electricity consumption in New England was largely driven by Massachusetts, where electricity sales fell by 6 percent between 2011 and 2015.[14] Not coincidentally, the state's energy efficiency efforts are ranked first in the country[15]. In a sign that this decline may be structural, and not merely cyclical, PJM, the largest organized electricity market in the country, revised its load forecasting methodology in 2015 to account for increased energy efficiency and distributed generation.[16] The EIA also recently started providing monthly estimates of distributed generation from solar panels.[17]

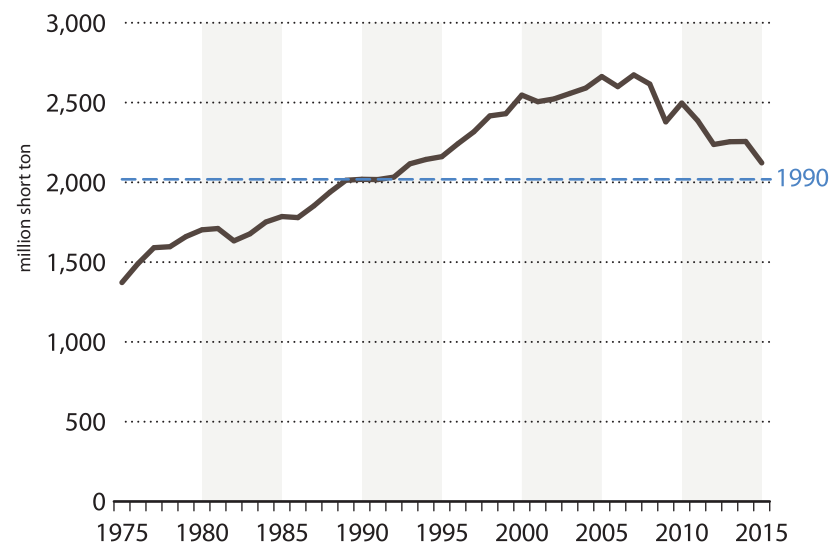
Lack of new demand and rising output from low-carbon sources have underpinned three major trends in the U.S. electric sector: declining CO_2 emissions, low wholesale electricity prices, and coal's shrinking role as a source of electricity.

Declining CO_2 Emissions

In the context of the slackening demand, a steady rise in the share of renewable sources of electricity along with an ongoing switch to natural gas from coal and oil has continued to drive down power sector CO_2 emissions. Between 2005 and 2014 emissions from power plants declined by 15 percent (see Figure 7).[18] Preliminary data suggest that they fell by another 6 percent in 2015 from 2014, leaving them at their lowest level in 22 years, and just 5 percent above 1990 levels.[19] This matters because reductions in the electric sector will be key to achieving the recently established U.S. national climate target. In advance of the UN climate conference held in Paris in late 2015, the U.S. committed to reducing its economy-wide GHG emissions 26 to 28 percent below 2005 levels by

FIGURE 7

CO_2 Emissions from the Electric Power Sector



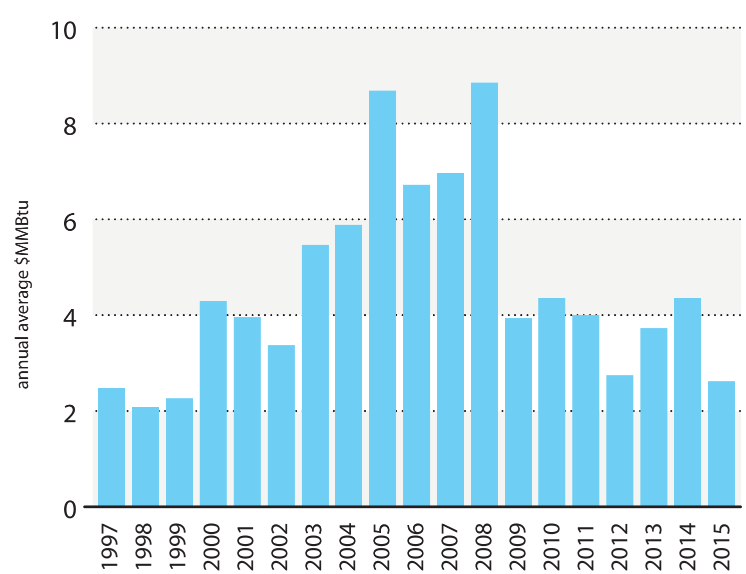
2025.[20] A total of 194 other countries also submitted goals and adopted an agreement aimed at limiting global warming to 2 degrees Celsius above pre-industrial levels.[21] While the U.S. will seek reductions from all sectors of the economy, a large share of the the cuts required by 2025 to reach the committed level of pollution reduction will come from the electric sector.

Falling Electricity Prices

Second, wholesale electricity prices–the prices paid by utility companies when they purchase power for their customers and large industrial users–are trending down at major trading hubs across the country. Since 2008, on average, they have declined by 40 percent.[22] This sharp fall in prices is mainly due to record low natural gas prices and, to some extent, the rising share of renewable resources, driven partly by government policies. The marginal cost of supply in most power markets has dropped as a result. Electricity prices are set by the cost of production at the marginal electricity generating resource. Because natural gas-fired power plants are often on the margin around much of the U.S., and fuel costs account for a majority of their avoidable costs of generation, electricity prices usually follow natural gas prices. Natural gas spot prices at the Henry Hub in Louisiana, a major price benchmark, averaged $2.61 per MMBtu in 2015, the lowest annual average level since 1999 (see Figure 8).[23]

FIGURE 8

Henry Hub Natural Gas Spot Price

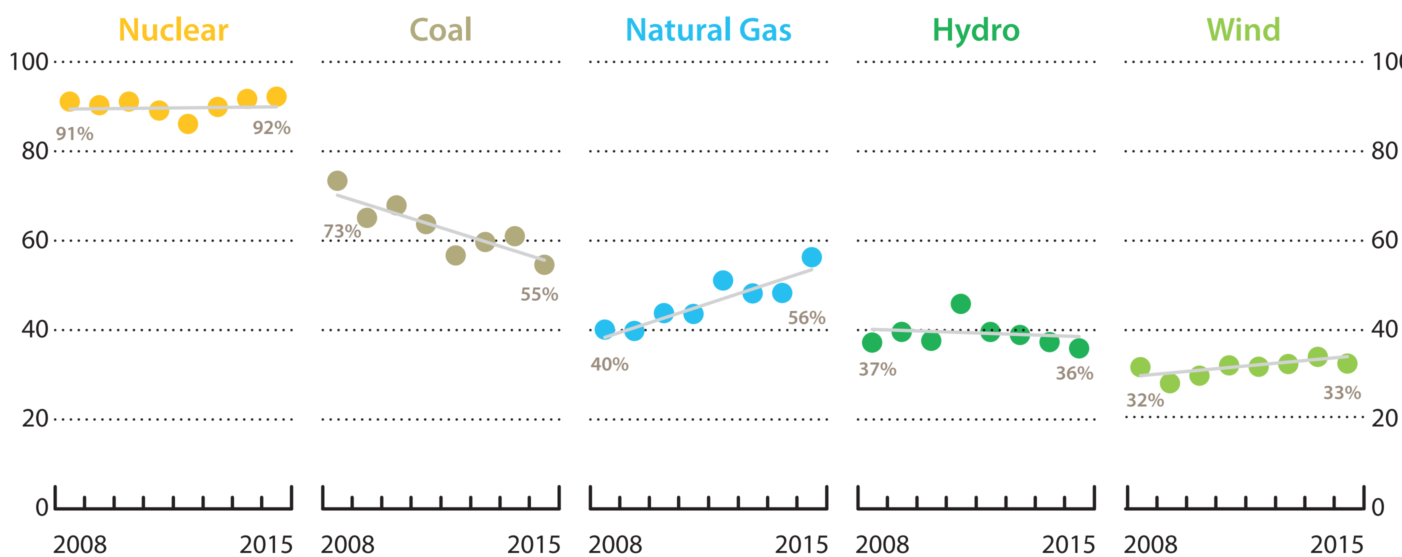


A steady rise in the level of renewables, supported by federal and state level policies (federal production tax credit, state renewable portfolio standards, etc.), has further reinforced the downward trend in electricity prices. Since renewable sources have virtually no marginal cost (i.e., no fuel cost), increased contributions from renewables shift the electricity supply curve outward resulting in a lower market clearing price for the same demand. In general, the higher the share of renewable energy the lower the wholesale price of electricity, all else being equal. As the level of renewable generation increases, the chances that electricity prices will hover around zero during some hours of the day will also increase. Prices may also dip below zero if, for example, wind projects bid in negative prices, while relying on the federal production tax credit to be made whole. Indeed, electricity prices have been pushed into negative territory with increasing frequency in several markets across the country. In California rising wind and solar resources are giving rise to negative spot prices more often than before.[24] In Texas power prices remained close to zero on several occasions for prolonged periods of time.[25] And at the Indiana hub, MISO prices often dip below zero during nights and weekends when wind output is high and demand low.[26]

One consequence of lower electricity prices is that merchant power plants in deregulated electricity markets are coming under increased financial strain as energy revenues fall and capacity payments, where they exist, are insufficient to offset lost energy revenues Because many such plants are price takers, they depend on clearing prices of electricity being sufficiently high to remain profitable. Thus, an outlook for a continued low power price environment has given rise to an industry trend of selling off merchant power plants.[27] In the last three years

FIGURE 9

Annual Capacity Factors for Select Fuels and Technologies
(percent)



Capacity factors measure the extent to which a power plant is utilized over the course of time. The technical definition is the ratio of the electrical energy produced by a generating unit to the electrical energy that could have been produced assuming continuous full power operation. Coal plant utilization has declined in recent years; the average annual capacity factor of coal plants in the U.S. dropped from 73 percent in 2008 to 55 percent in 2015, while over the same time period, natural gas combined-cycle capacity factors rose, from 40 to 56 percent. Nuclear plants have high utilization rates, consistently running at a 90 percent average capacity factor. Hydropower and wind capacity factors are lower, but have also remained relatively constant over the past eight years. In the case of wind, average capacity factors have remained largely unchanged, in part because gains in high-wind resource areas due to technology improvements–better turbine designs, higher hub heights, bigger rotor diameters, etc.–were canceled out by capacity factors of new projects in traditionally low-wind resource locations, which became economically feasible because of the same technology improvements.

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION. ELECTRIC POWER MONTHLY, TABLES 6.7A AND 6.7B. FEBRUARY 2016

Ameren,[28] Duke,[29] and PPL[30] have abandoned the independent power generation business to concentrate on their rate-regulated utilities. Another power producer, AEP, has put most of its merchant plants up for sale.[31] The company has indicated that this for-sale list will likely grow after federal regulators recently rejected income guarantees to some of its plants in Ohio.[32]

Coal's Shrinking Role

That leads to the third major trend: a declining share of coal in the electricity mix. Coal-fired plants, the mainstay of the U.S. electric sector for most of the 20th century, have traditionally supplied much of the country's electricity needs. They have tended to be large facilities that run around-the-clock throughout the year. Output from such plants provided an average 51 percent of total U.S. electricity generation between 1949 and 2005.[33] Since then, however, coal's share has declined at a steady clip. In 2015, U.S. coal-fired plants accounted for just 33 percent of total output, down from 57 percent in 1988.[34] The combined effects of falling electricity prices and new environmental regulations (see section below) have crimped profit margins to the point where many coal-fired power plants struggle to remain profitable. In addition, coal plants are not dispatched as often, as competitive renewable sources and natural gas-fired generators have moved in. Capacity utilization rates of coal plants dropped 19 percentage points between 2008 and 2015 (see Figure 9). Further, because coal plants often sign long term take-or-pay contracts for the supply of coal, they continue to incur fuel costs even when they do not run. At the end of 2015, coal stockpiles at power plants across the U.S. totaled nearly 200 million tons, the highest year-end inventories in over 25 years.[35] Many are finding the circumstances unsustainable and are exiting the industry. Since 2010, 89 GW of coal capacity, or a quater of the U.S. coal fleet, has shut down or announced plans to retire.[36] Some parts of the country such as New York and New England have retired virtually all of their coal plants.

In addition to low electricity demand growth, the major driving forces behind these trends reshaping the electric sector include an abundant supply of low cost natural gas, falling renewable technology costs, and policy support for wind and solar energy resources.

Low Gas Prices Likely to Continue

First, the shale gas revolution. In the 1990s and 2000s, breakthroughs in two key technologies gave rise to the U.S. shale revolution that made low natural gas prices possible. Technological advances in horizontal drilling and hydraulic fracturing allowed access to large volumes of shale gas that were previously uneconomical to produce. They helped unlock gas trapped within shale formations or fine-grained sedimentary rocks. As a consequence, production at shale formations in Texas and Oklahoma started rising rapidly around 2008. By 2015, shale formations in 10 states accounted for more than 50 percent of total U.S. natural gas production.[37] They helped boost production to 27 trillion cubic feet in 2015 (up 34 percent since 2008) making the U.S. the world's leading producer of natural gas.[38] Largely as a result, prices slumped from a high of $13 per MMBtu in mid-2008 to less than $2 per MMbtu in December of 2015.[39] This, in turn, led to the increased use of natural gas in the electric sector, a key driver of demand. In the decade prior to 2015, annual consumption of natural gas at power plants rose by 64 percent to nearly 10 trillion cubic feet.[40]

Even though production data seem to indicate that U.S. natural gas production has stagnated and may even be declining,[41] all of the fundamentals point to continued oversupply and low prices in the medium term. The Utica shale formation, a major new source of natural gas that recently came online and is ramping up output quickly, has a breakeven price that may be well under $2 per MMBtu.[42] At that price, some companies believe that they can generate returns of more than 50 percent in the current market.[43] Others report similar figures at the neighboring Marcellus shale formation.[44] At the same time, U.S. proven natural gas reserves, which stood at 388 trillion cubic feet at the end of 2014, are at record high levels, nearly double the amount from just ten years ago.[45] Even if there was an uptick in prices in the short term, it is likely that additional supply could be brought online relatively quickly. This is because shale gas projects in well-established shale plays require relatively less lead-time to bring online than conventional projects. In addition, there are a large number of drilled but uncompleted wells, and some producers are cutting back output from existing wells in the current low price environment.[46]

Renewables Will Get Cheaper…

Second, wind and solar technologies have gotten better even as their installation costs have fallen in recent years. Average capacity, hub height, and rotor diameter of wind turbines and conversion efficiencies of solar cells have all increased significantly.[47] As a result of these performance improvements, combined with rapidly falling installation costs, between 2009 and 2015 the levelized cost of generating electricity (LCOE: total cost of installing and running a project divided by expected electricity output over the project's lifetime) from wind and solar resources fell by 61 percent and 82 percent, respectively.[48] That is one reason why 35 GW of wind and 27 GW of solar, 47 percent and 97 percent of the U.S. wind and solar fleet respectively, were added in just the past five years.[49] Declining costs and policy support through tax incentives and other means have translated into renewable projects offering record low power contract prices. Wind power purchase agreements (PPAs) signed in 2014 averaged just $24 per MWh, down almost 66 percent since 2009.[50] Utilities developing wind projects have reported even lower contract prices in 2015.[51] Similarly, solar PPAs in California have declined from about $90 per MWh in 2011 to less than $55 per MWh in 2016, a drop of nearly 40 percent.[52] As a consequence, solar power has become increasingly competitive even in parts of the country not traditionally associated with it. States like Arkansas and Alabama that have had little solar development in the past are increasingly seeing projects sign PPAs in the $50-60 per MWh range. [53]

By comparison, total generating costs at the most efficient natural gas combined cycle plants remain at just over $52 per MWh.[54] Thus, falling capital costs and tax incentives put wind and solar on par with natural gas, or cheaper, in several markets around the country. However, these cost comparisons do not include additional system costs that are often necessary to integrate renewable energy into the grid, largely due to their variable nature. ERCOT, the Texas grid operator, calculates that additional costs of approximately $0.50 per MWh are necessary to integrate up to 10 GW of wind into its system.[55] But costs generally tend to rise with the share of variable energy. Some estimates point to integration costs of about $12 per MWh to accommodate wind penetration of up to about 40 percent of peak load in the system.[56] The best sites are also often far from large population centers making them more expensive to connect. For example, in 2005 state lawmakers in Texas authorized the building of significant transmission capacity out of West Texas (the windier part of the state, but where few people live) at a cost of $7 billion.[57] These costs, if allocated to renewables, reduce the competitiveness of renewable resources and can create significant barriers to entry, especially as their share of the fuel mix rises.

Regulatory incentives and policy obligations, the third major driving force, can help overcome these and other barriers and substantially boost the deployment of renewable energy even as they become cheaper to install and run. Twenty-nine states have renewable portfolio standards (RPS) that require utilities to ensure that a certain share of the electricity they sell comes from renewable energy sources.[58] Recently several states have raised their RPS requirement levels: California passed legislation to increase renewable energy requirements of its utilities to 50 percent by 2030,[59] while Oregon would require its utilities to reach the same level by 2040.[60]

At the federal level, tax credits are available to wind and solar projects based on production (PTC) and investment (ITC), respectively. At the end of 2015, the U.S. Congress extended these programs by another five years.[61] The ITC for both commercial and residential solar systems is currently set at 30 percent of the investment in a qualifying solar project and, under the terms of the extension, will continue at 30 percent through 2019. The ITC will then taper off in yearly increments to settle at 10 percent in 2022 for non-residential systems and will phase out entirely in 2022 for residential systems. The PTC is a tax credit earned for every KWh of electricity generated by wind projects. The PTC for wind energy is 2.3 cents per KWh for facilities commencing construction in 2016, followed by incremental reductions in value before expiring in January 2020. The PTC translates into significant value ($23 per MWh), with the potential to double revenues of wind projects at prevailing power prices, which are in the $20-30 per MWh range. As noted earlier, the PTC would also allow wind projects to continue to make money when wholesale power prices fall to zero, or even dip into negative territory.

Continuation of the tax credits is widely expected to have significant implications for investment in renewable energy. As wind and solar costs have declined in recent years, production cost models have projected higher penetration rates for both technologies. The extensions of the tax credits will only increase projected penetration rates in coming years. Several studies have estimated the short-term effects of these extensions. Their projections indicate that the extensions will result in between 37 and 95 GW of more renewable capacity additions by 2020 than would otherwise occur without the extensions.[62] For comparison, the existing fleet of solar and wind installations added up to 75 GW at the end of 2014.[63]

…But a New Business Model Is Required

Further, 41 states and the District of Columbia have "net metering" rules that allow utility customers with on-site generation (primarily solar panels) to sell any excess electricity to their utility providers at retail rates and receive credit on their utility bills.[64] Net metering policies have been credited with driving the explosive growth of solar panels in the U.S., particularly in the residential sector.[65] At the end of 2015 total capacity of solar panel installations (distributed and utility) in the U.S. amounted to 25 GW, up more than 12 times from just 2 GW in 2010.[66] Another 10 GW is scheduled to come online in 2016, the most of any single source of electricity.[67]

Net metering policies, however, have given rise to contentious debates in several states. Over 60 percent of all states with net metering policies limit in some form the total amount of generating capacity for which customers may be credited on their retail bills.[68] In several states that are leading the solar boom, most notably California, Nevada, and Massachusetts, the respective capacity limits have already been reached or will soon be. When the limits are exhausted only further regulatory or legislative action can enable new projects to take advantage of the terms available under net metering policies. But any such effort leads to a contentious debate. Developers of solar projects argue that the inability of customers to receive credit for their distributed generation at the full retail rate can upend the economics of new distributed solar installations and significantly dampen their deployment. They contend that rooftop solar panels reduce strain on the electricity distribution system and help utilities better manage their peak demand requirements, and that current net metering policies reflect these benefits. But others, including utilities, contend that retail rates paid under current policies are overly generous, because retail rates include not just energy charges, but also distribution and generation capacity costs. They also believe that such net metering policies shift maintenance and development costs of the electricity grid to customers that do not use solar panels.

Storage Will Be Key

But even when cheap renewable resources are combined with supportive state and federal policies, utilities find it difficult to replace the need for traditional baseload capacity. Their biggest problem is storing the electricity they produce for times when the sun does not shine, the wind does not blow, or both. The ability to store excess energy during sunnier and windier periods holds the promise of transforming wind and solar power into resources that could potentially deliver power on-demand, at any time of the day or night. Cost-effective storage solutions could also open up new income sources by allowing them to participate in the capacity and ancillary services markets. Capacity (availability of resources to deliver power when needed) and ancillary service support (power quality and voltage regulation), two elements crucial to grid reliability, have traditionally been supported by conventional hydro, fossil, and nuclear energy.

Storage, other than pumped storage, however, is expensive, and currently prohibitively so at scales required to replace conventional generating resources. Recent breakthroughs and cost declines in storage technology, however, indicate that this may be about to change. The average price of lithium-ion batteries (the dominant technology) fell by over 50 percent in the three years to 2015.[69] They are forecast to decline at least 15 percent annually between now and 2020.[70] Partly as a consequence, annual installations of energy storage projects in the U.S. reached 221 MW in 2015, up 243 percent since 2014.[71] Deployments are expected to reach over 1 GW per year by 2019, taking the cumulative installed capacity to over 4 GW by 2020, most of which will be at the utility scale. [72] By comparison, the total U.S. installed wind and solar capacity at the end of 2015 was about 100 GW. [73]

Going forward, in the near- to mid-term the outlook points to the three key trends continuing: power sector CO_2 emissions will continue to decline; coal's share of the U.S. generation mix will become smaller; and, electricity prices will remain beholden to weak demand growth, low natural gas prices, and a growing share of renewables. Low prices and environmental regulations will continue to drive coal plants out of the market. Existing baseload sources of power, including nuclear plants, will find it harder to remain profitable. And if technological breakthroughs can effectively extend the capacity factors of intermittent renewables, the trends may accelerate significantly. They could bring into even sharper relief the conundrum currently facing the electric sector: is the existing utility business model adequate to attract investments into the sector to maintain critical infrastructure?

Environmental Regulatory Trends

The discussion that follows highlights some of the key federal air quality and climate change regulations affecting the electric power sector. Power plant operators are also subject to waste and water quality regulations that are not discussed in this report.

Clean Power Plan

On August 3, 2015, EPA finalized the Clean Power Plan to regulate CO_2 emissions from existing power plants under Section 111(d) of the Clean Air Act. EPA projects that the rule, which applies to fossil fuel-fired electric generating units (except simple cycle turbines) that had commenced operation or construction as of January 8, 2014, will reduce CO_2 emissions from the electric sector by 32 percent below 2005 levels by 2030.

Under the rule, EPA sets emissions limits for power plants and states can elect to comply with the applicable rate-based (lb CO_2/MWh) standards or a mass-based (tons CO_2) target. EPA has set interim and final goals for each approach. Many states expect to rely on market-based trading programs to achieve compliance. The rules require initial compliance in 2022. Prior to the start states must submit compliance plans identifying their choice of approach to EPA. However, the timing of the clean Power Plan is uncertain given the U.S. Supreme Court's stay of the rule.

Legal challenges to the Clean Power Plan were filed immediately after the rule was published. On January 21, 2016, the U.S. Court of Appeals for the D.C. Circuit denied several motions to stay the final carbon standards for existing power plants. However, on February 9, 2016, in an unprecedented action, the U.S. Supreme Court granted a stay, or temporary suspension, of the rule with a 5 to 4 vote. There have been mixed reactions from states. Some have committed to moving forward with stakeholder engagement and state plan design while others have postponed their planning processes during the litigation. The D.C. Circuit will hear oral argument of the Clean Power Plan case before the en banc (full panel) on September 27, 2016.

Carbon Pollution Standards for New Sources

On August 3, 2015, EPA also released a final rule regulating CO_2 emissions from new, modified, and reconstructed power plants under Section 111(b) of the Clean Air Act. Regulated sources include steam generating units and stationary combustion turbines (including simple cycle) capable of supplying more than 25 MW to the grid. New sources are defined as those commencing construction on or after January 8, 2014. The performance standards for new baseload steam boilers and combustion turbines are 1,400 and 1,000 lb CO_2/MWh, respectively. The steam unit standard effectively prohibits the construction of any new coal plants without some form of carbon capture (the average CO_2 rate for coal-fired units among the top 100 producers in 2014 was 2,185 lb/MWh).

The new source rule has also been challenged in the D.C. Circuit by a collection of states, energy companies, and trade associations. The briefing and oral argument schedules have not yet been set.

Cross-State Air Pollution Rule

In 2011, EPA finalized the Cross State Air Pollution Rule (CSAPR), which established a trading program to reduce NOx and SO_2 emissions from coal-, oil-, and natural gas-fired power plants in 28 states. The rule was challenged by a number of states, utilities, and industry groups and in August 2012, the D.C. Circuit vacated the rule. EPA challenged this ruling, and on April 29, 2014, the U.S. Supreme Court upheld CSAPR, reversing the D.C. Circuit's decision. However, in response to challenges to EPA's emissions budgets, on July 28, 2015, the D.C. Circuit held that the SO_2 budgets for four states and the NOx budgets for eleven states were invalid and remanded them to EPA without vacatur. In response, EPA released the proposed CSAPR Updating Rule in December 2015, which proposes new NOx budgets for 23 states. The proposed budgets would require cuts from upwind states that have not previously been required to make substantial NOx reductions. EPA is expected to finalize the proposed updated NOx budgets by summer 2016 and act on the remanded SO_2 budgets in fall 2016.

Mercury Air Toxics Standards

In December 2011, EPA released the first-ever federal limits on hazardous air pollutants from coal- and oil-fired power plants, known as the Mercury and Air Toxics Standards (MATS). These standards require overall reductions in mercury emissions of 90 percent, as well as reductions in acid gases and particulate matter. The rule's compliance deadline was April 15, 2015, with power generators achieving compliance through three primary strategies: installation of controls, conversion to natural gas, and retirement. A one year compliance extension was also made available and granted to nearly all units that requested it, pushing compliance to April 2016 for approximately 40 percent of the coal fleet. Given the financial pressures facing many coal units, a large number of operators, especially those of smaller units, determined it was not economical to install controls and chose retirement. As such, the MATS rule likely contributed to the over 35 GW of coal capacity scheduled to retire in 2015 and 2016.

MATS was initially upheld by the D.C. Circuit in April 2014. However, in June 2015, the U.S. Supreme Court ruled that EPA did not properly consider costs while developing the rule and remanded the issue, leaving the rule in place. On December 1, 2015, EPA issued a proposed Supplemental Finding that consideration of costs does not alter its previous determination that it is appropriate to regulate toxic air pollution from power plants. EPA's final supplemental finding was issued in April 2016. The final finding affirmed that it was appropriate and necessary to regulate toxic air pollution from power plants. Industry groups have already sued the Agency over this finding. However, both the D.C. Circuit and U.S. Supreme Court have rejected motions to stay the rule pending the outcome of the costs litigation. Regardless of the Court's final decision, the majority of affected units have already completed their compliance strategies. Given the investment, planning, and permitting required for such activities, as well as low natural gas prices, it is unlikely that any decision against EPA would significantly impact announced coal retirements.

In meeting the April 2016 compliance requirement of EPA's MATS Rule, Entergy significantly reduced mercury emission levels at its Independence, Nelson 6, and White Bluff (pictured) coal facilities by installing mercury emission controls that use activated carbon injection.
PHOTO CREDIT: ENTERGY

Regional Haze

EPA's Regional Haze Rule, finalized in 1999, is different from many other rules in that its goal is not related directly to protecting human health. The program's purpose is to return visibility at 156 national parks and wilderness areas back to natural levels. A major component of the rule is implementation of Best Available Retrofit Technology (BART) at large emission sources, many of them power plants, built between 1962 and 1977 whose emissions remain uncontrolled, impairing visibility. States and EPA have determined that a significant number of power plants, notably large Western coal-fired units, need to install controls to meet visibility goals. Some units must install tens or hundreds of millions of dollars in controls, including flue gas desulfurization, baghouses, and selective catalytic reduction. Final control requirement determinations have been made for affected power plants. States and utilities subject to federal plans (implemented by EPA after the Agency determined state plans were not adequate) have challenged EPA's determinations, but federal courts have thus far ruled in favor of EPA. The majority of affected units must install controls between 2016 and 2020. In April 2016, the Agency proposed updated revisions to the rule intended to provide greater clarity and guidance to states.

Ozone and SO_2 Standards

EPA is required to periodically update National Ambient Air Quality Standards (NAAQS) for several common air pollutants that pose a threat to human health and the environment. In 2015, EPA finalized new ozone NAAQS and is currently in the process of implementing the 2010 SO_2 NAAQS. Both standards are more stringent than the previous requirements. NAAQS affect the permitting process and may require permits for power plants and other sources to include more stringent control requirements in order to bring a region into attainment or prevent it from falling out of attainment. Coal power plants in particular may be affected as they are large sources of both SO_2 and NO_x, an ozone precursor. Attainment for the previous ozone standard (2008 NAAQS) is due between 2015 and 2021, depending on the severity of nonattainment. Attainment deadlines for the 2010 SO_2 and new 2015 ozone NAAQS are not finalized since all areas have not been classified. The earliest attainment deadlines are in 2018, but most are after 2020.

Emissions of the 100 Largest Electric Power Producers

In 2014, the 100 largest power producers in the U.S. generated 87 percent of the industry's air pollution emissions. The 100 largest power producers emitted in aggregate approximately 2.82 million tons of SO_2, 1.43 million tons of NOx, 18.68 tons of mercury, and 1.96 billion tons of CO_2. Air pollution emissions from power plants are highly concentrated among a small number of producers. Ten producers were responsible for 56 percent of the SO_2, 43 percent of the NOx, 49 percent of the mercury, and 40 percent of the CO_2 emissions from the U.S. electric power production sector.

Electric power producers' emission levels and emission rates vary significantly due to the amount of power produced, the efficiency of the technology used in producing the power, the fuel used to generate the power, and installed pollution controls. The average and median emission levels (tons) and emission rates (lb/MWh) shown in Table 1 provide benchmark measures of overall industry emissions that can be used as reference points to evaluate the emissions performance of individual power producers.

Across the industry, power plant emissions of SO_2 and NOx have decreased and CO_2 emissions have increased since 1990. The power industry has dramatically reduced its SO_2 and NOx emissions. In 2014, power plant SO_2 and NOx emissions were 80 percent and 75 percent lower, respectively, than they were in 1990. In 2014, power plant CO_2 emissions were 14 percent higher than they were in 1990. However, in recent years, from 2008 through 2014, power plant CO_2 emissions decreased by 12 percent. Emissions rates have also dropped, with 2014 power plant SO_2, NOx, and CO_2 emissions rates 85 percent, 81 percent, and 16 percent lower, respectively, than they were in 1990. Mercury emissions from power plants have decreased 55 percent since 2000 (the first year that mercury emissions were reported by the industry under the Toxics Release Inventory). The mercury emission rate decreased 44 percent between 2000 and 2014. Collectively, power plants are responsible for a declining share of U.S. air pollution emissions. In 2014, power plants were responsible for about 62 percent of SO_2 emissions, 14 percent of NOx emissions, 58 percent of mercury emissions, and 37 percent of CO_2 emissions.

TABLE 1

Emissions Data for 100 Largest Power Producers

in order of 2014 generation

Rank	Owner	Ownership Type*	2014 Generation (MWh)			2014 Emissions (tons)				Emission Rates (lb/MWh)									
										All Generating Sources			Fossil Fuel Plants †			Coal Plants ††			
			Total	Fossil Fuel	Coal	SO_2	NOx	CO_2	Hg**	SO_2	NOx	CO_2	SO_2	NOx	CO_2	SO_2	NOx	CO_2	Hg†††
1	Duke	investor-owned corp.	245,023,141	171,183,604	103,575,507	164,089	100,852	138,347,641	0.50	1.3	0.8	1,129	1.9	1.2	1,616	3.2	1.8	2,081	0.01
2	Southern	investor-owned corp.	190,901,034	154,156,924	78,406,024	243,480	79,230	117,634,394	1.32	2.6	0.8	1,232	3.2	1.0	1,523	6.2	1.9	2,158	0.03
3	NextEra Energy	investor-owned corp.	182,996,964	103,661,668	5,030,146	7,116	15,681	48,573,857	0.04	0.1	0.2	531	0.1	0.3	937	1.9	2.1	2,233	0.02
4	Exelon	investor-owned corp.	177,970,939	14,157,392	209,533	1,812	2,282	7,138,620	0.00	0.0	0.0	80	0.2	0.3	1,008	5.2	1.6	2,784	0.00
5	AEP	investor-owned corp.	162,941,747	143,536,074	124,311,557	320,894	111,446	141,369,243	2.22	3.9	1.4	1,735	4.5	1.6	1,970	5.2	1.7	2,106	0.04
6	Tennessee Valley Authority	federal power authority	142,854,316	75,022,438	62,410,231	135,848	51,572	72,859,872	0.45	1.9	0.7	1,020	3.6	1.4	1,942	4.4	1.6	2,153	0.01
7	NRG	investor-owned corp.	136,695,515	117,650,853	85,600,534	256,511	75,036	113,149,469	1.38	3.8	1.1	1,655	4.4	1.3	1,922	5.9	1.6	2,245	0.03
8	Entergy	investor-owned corp.	130,325,124	53,519,177	14,804,105	47,242	38,535	37,875,560	0.38	0.7	0.6	581	1.8	1.4	1,399	6.4	2.6	2,250	0.05
9	Berkshire Hathaway Energy	privately held corp.	118,927,937	94,498,783	66,086,435	80,717	78,410	86,567,330	0.89	1.4	1.3	1,456	1.7	1.7	1,832	2.4	2.3	2,232	0.03
10	Calpine	investor-owned corp.	101,755,994	95,642,274	-	342	7,201	41,814,872	-	0.0	0.1	822	0.0	0.1	872	-	-	-	-
11	FirstEnergy	investor-owned corp.	95,367,708	64,325,962	59,047,264	94,588	76,110	65,992,863	0.60	2.0	1.6	1,384	2.9	2.4	2,052	3.1	2.5	2,127	0.02
12	Dominion	investor-owned corp.	92,870,371	46,688,753	25,230,737	28,669	18,731	36,337,843	0.25	0.6	0.4	783	1.2	0.8	1,557	2.1	1.2	2,115	0.02
13	PPL	investor-owned corp.	86,623,785	68,170,588	55,469,647	112,904	72,645	66,605,001	0.60	2.6	1.7	1,538	3.3	2.1	1,954	4.1	2.5	2,168	0.02
14	US Corps of Engineers	federal power authority	73,344,880	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Xcel	investor-owned corp.	73,181,296	57,725,524	43,736,666	60,751	46,943	56,059,089	0.52	1.7	1.3	1,532	2.1	1.6	1,942	2.8	2.0	2,221	0.02
16	Energy Future Holdings	privately held corp.	68,449,906	49,814,130	48,889,001	163,169	30,271	57,700,829	1.98	4.8	0.9	1,686	6.6	1.2	2,317	6.7	1.2	2,332	0.08
17	Dynegy	investor-owned corp.	58,730,627	58,730,627	42,658,108	56,190	21,627	55,616,642	0.20	1.9	0.7	1,894	1.9	0.7	1,894	2.6	1.0	2,263	0.01
18	PSEG	investor-owned corp.	54,141,068	24,829,017	6,455,919	9,183	10,880	15,428,753	0.07	0.3	0.4	570	0.7	0.9	1,243	2.7	2.8	2,075	0.02
19	Ameren	investor-owned corp.	43,550,658	33,172,332	33,023,203	63,743	20,000	33,275,242	0.53	2.9	0.9	1,528	3.8	1.2	2,006	3.9	1.2	2,011	0.03
20	DTE Energy	investor-owned corp.	42,774,444	32,634,662	30,757,170	79,172	31,794	35,414,145	0.51	3.7	1.5	1,656	4.8	1.9	2,139	5.1	2.0	2,202	0.03
21	US Bureau of Reclamation	federal power authority	42,052,600	4,203,190	4,199,820	1,377	4,347	4,434,699	0.07	0.1	0.2	211	0.7	2.1	2,110	0.7	2.1	2,111	0.04
22	AES	investor-owned corp.	37,641,014	35,028,782	32,147,008	132,310	33,880	36,539,077	0.23	7.0	1.8	1,941	7.6	1.9	2,086	8.2	2.1	2,151	0.01
23	GDF Suez	foreign-owned corp.	32,714,256	31,104,113	5,451,717	17,287	6,009	17,579,419	0.12	1.1	0.4	1,075	1.1	0.4	1,129	6.3	1.2	2,112	0.04
24	San Antonio City	municipality	29,248,802	20,988,135	14,957,634	17,147	7,630	18,658,230	0.18	1.2	0.5	1,276	1.6	0.7	1,778	2.3	0.9	2,115	0.02
25	PG&E	investor-owned corp.	28,973,010	6,088,866	-	12	125	2,666,834	-	0.0	0.0	184	0.0	0.0	876	-	-	-	-
26	Energy Capital Partners	privately held corp.	28,562,088	25,589,351	9,104,671	4,829	4,807	17,920,552	0.03	0.3	0.3	1,255	0.4	0.4	1,401	1.0	0.9	2,289	0.01
27	Salt River Project	power district	27,933,890	22,165,136	15,365,898	5,734	18,744	19,785,614	0.14	0.4	1.3	1,417	0.5	1.7	1,785	0.7	2.4	2,186	0.02
28	Pinnacle West	investor-owned corp.	27,576,169	17,805,261	12,067,429	7,197	22,576	15,964,010	0.21	0.5	1.6	1,158	0.8	2.5	1,793	1.2	3.7	2,181	0.03
29	New York Power Authority	state power authority	25,737,285	4,864,863	-	24	275	2,220,658	-	0.0	0.0	173	0.0	0.1	913	-	-	-	-
30	Westar	investor-owned corp.	25,306,605	20,858,504	19,488,782	14,498	15,317	23,726,009	0.29	1.1	1.2	1,875	1.4	1.5	2,275	1.5	1.5	2,343	0.03
31	General Electric	investor-owned corp.	25,190,811	24,248,925	11,939,206	124,083	23,073	17,900,205	0.28	9.9	1.8	1,421	10.2	1.9	1,476	20.8	3.7	2,098	0.05
32	Great Plains Energy	investor-owned corp.	24,928,450	20,393,850	20,032,745	22,377	14,014	22,177,141	0.30	1.8	1.1	1,779	2.2	1.4	2,175	2.2	1.4	2,177	0.03
33	Wisconsin Energy	investor-owned corp.	24,134,951	22,868,966	19,624,685	11,529	11,629	23,359,390	0.09	1.0	1.0	1,936	1.0	1.0	2,043	1.2	1.1	2,228	0.01
34	SCANA	investor-owned corp.	23,379,687	18,167,401	11,901,788	16,768	8,197	14,292,542	0.03	1.4	0.7	1,223	1.8	0.9	1,573	2.8	1.3	1,940	0.01
35	Santee Cooper	state power authority	23,098,987	20,406,001	16,542,199	6,787	6,630	18,903,619	0.05	0.6	0.6	1,637	0.7	0.6	1,853	0.8	0.8	2,077	0.01
36	OGE	investor-owned corp.	22,820,544	21,174,680	13,901,857	34,633	18,784	19,884,966	0.22	3.0	1.6	1,743	3.3	1.8	1,878	5.0	2.2	2,314	0.03
37	Oglethorpe	cooperative	22,260,469	12,489,414	7,120,415	2,298	4,915	10,418,625	0.05	0.2	0.4	936	0.4	0.8	1,668	0.6	1.3	2,227	0.01
38	CMS Energy	investor-owned corp.	21,804,475	19,638,502	15,817,920	54,097	14,043	20,618,861	0.35	5.0	1.3	1,891	5.5	1.4	2,008	6.8	1.6	2,231	0.04
39	EDF	foreign-owned corp.	21,660,868	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	LS Power	privately held corp.	19,750,427	18,884,716	6,196,226	3,176	3,464	12,586,970	0.07	0.3	0.4	1,275	0.3	0.4	1,333	1.0	0.6	2,161	0.02
41	TECO	investor-owned corp.	18,665,279	18,665,279	11,530,909	12,251	5,710	15,293,194	0.03	1.3	0.6	1,639	1.2	0.6	1,639	1.9	0.9	2,090	0.00
42	Alliant Energy	investor-owned corp.	18,632,902	16,698,857	13,680,237	39,154	12,616	17,304,163	0.32	4.2	1.4	1,857	4.7	1.5	2,072	5.7	1.8	2,336	0.05
43	Basin Electric Power Coop	cooperative	18,418,835	17,313,962	16,588,989	18,432	20,560	19,921,483	0.44	2.0	2.2	2,163	2.1	2.4	2,301	2.2	2.5	2,357	0.05
44	ArcLight Capital	privately held corp.	16,845,306	14,368,288	8,418,049	13,826	12,971	11,268,139	0.09	1.6	1.5	1,338	1.9	1.8	1,568	3.3	3.0	2,015	0.02
45	NE Public Power District	power district	16,495,833	10,320,124	10,104,100	27,726	11,022	11,352,329	0.30	3.4	1.3	1,376	5.4	2.1	2,200	5.5	2.2	2,223	0.06
46	Omaha Public Power District	power district	16,177,058	11,945,475	11,842,733	27,379	11,436	12,996,938	0.24	3.4	1.4	1,607	4.6	1.9	2,176	4.6	1.9	2,180	0.04
47	Iberdrola	foreign-owned corp.	15,890,607	738,605	-	2	49	305,572	-	0.0	0.0	38	0.0	0.1	827	-	-	-	-
48	NC Public Power	municipality	15,538,131	901,053	896,746	1,154	711	1,032,527	0.01	0.1	0.1	133	2.6	1.6	2,292	2.6	1.6	2,288	0.01
49	Associated Electric Coop	cooperative	15,005,698	15,005,698	12,104,703	24,976	26,333	14,169,182	0.13	3.3	3.5	1,889	3.3	3.5	1,889	4.1	4.3	2,128	0.02
50	NiSource	investor-owned corp.	14,927,556	14,901,973	12,397,206	25,525	10,165	15,495,231	0.15	3.4	1.4	2,076	3.4	1.4	2,080	4.1	1.6	2,336	0.02
51	Tenaska	privately held corp.	14,619,451	14,310,594	-	251	1,406	6,736,347	-	0.0	0.2	922	0.0	0.2	941	-	-	-	-
52	JEA	municipality	14,180,152	14,180,152	8,686,552	17,591	13,408	12,788,046	0.06	2.5	1.9	1,804	2.5	1.9	1,804	4.0	3.0	2,152	0.01

* Breakdown of ownership categories provided in endnote 2 — privately/investor owned — public power — cooperative

** Mercury emissions are based on 2014 TRI data for coal plants
† Fossil fuel emission rate = pounds of pollution per MWh of electricity produced from fossil fuel
†† Coal emission rate = pounds of pollution per MWh of electricity produced from coal
††† Mercury emissions rate = pounds of mercury per gigawatt hour (GWh) of electricity produced from coal

			2014 Generation (MWh)			2014 Emissions (tons)				Emission Rates (lb/MWh)									
										All Generating Sources			Fossil Fuel Plants †			Coal Plants ††			
Rank	Owner	Ownership Type*	Total	Fossil Fuel	Coal	SO_2	NOx	CO_2	Hg**	SO_2	NOx	CO_2	SO_2	NOx	CO_2	SO_2	NOx	CO_2	Hg†††
53	IDACORP	investor-owned corp.	13,789,468	7,545,229	6,360,053	8,229	7,273	7,580,442	0.09	1.2	1.1	1,099	2.2	1.9	2,009	2.6	2.3	2,221	0.03
54	Rockland Capital	privately held corp.	13,610,713	13,374,756	226,149	316	1,035	5,891,531	0.00	0.0	0.2	866	0.0	0.2	881	1.9	4.4	2,316	0.01
55	Los Angeles City	municipality	13,545,481	10,964,914	3,664,040	1,227	4,036	7,575,896	0.06	0.2	0.6	1,119	0.2	0.7	1,382	0.7	2.1	2,111	0.04
56	Edison International	investor-owned corp.	13,300,527	6,315,450	-	14	128	2,741,845	-	0.0	0.0	412	0.0	0.0	868	-	-	-	-
57	Tri-State	cooperative	12,782,089	12,782,089	12,085,362	7,295	15,268	13,746,192	0.07	1.1	2.4	2,151	1.1	2.4	2,151	1.2	2.5	2,203	0.01
58	Occidental	investor-owned corp.	12,457,521	12,338,428	-	6	616	5,870,194	-	0.0	0.1	942	0.0	0.1	941	-	-	-	-
59	Intermountain Power Agency	power district	12,369,826	12,369,826	12,360,859	4,369	23,616	12,222,208	0.00	0.7	3.8	1,976	0.7	3.8	1,976	0.7	3.8	1,976	0.00
60	Riverstone	privately held corp.	12,078,898	12,078,898	6,438,581	14,658	5,435	10,030,519	0.02	2.4	0.9	1,661	2.4	0.9	1,661	4.4	1.4	2,257	0.01
61	Dow Chemical	investor-owned corp.	11,960,354	11,089,104	-	9	437	5,174,147	-	0.0	0.1	865	0.0	0.1	862	-	-	-	-
62	Municipal Elec. Auth. of GA	municipality	11,876,349	5,208,417	3,583,942	1,154	2,392	4,697,284	0.02	0.2	0.4	791	0.4	0.9	1,804	0.6	1.3	2,227	0.01
63	Puget Holdings	privately held corp.	11,637,976	8,651,354	4,509,455	3,574	5,665	7,085,936	0.02	0.6	1.0	1,218	0.8	1.3	1,638	1.6	2.4	2,303	0.01
64	Portland General Electric	investor-owned corp.	11,078,735	8,185,648	4,751,971	8,195	5,495	6,723,698	0.01	1.5	1.0	1,214	2.0	1.3	1,643	3.4	2.2	2,197	0.01
65	Exxon Mobil	investor-owned corp.	11,072,750	10,004,044	-	25	1,095	4,631,896	-	0.0	0.2	837	0.0	0.1	804	-	-	-	-
66	Arkansas Electric Coop	cooperative	10,984,408	10,309,546	9,858,161	26,604	13,488	11,045,723	0.24	4.8	2.5	2,011	5.2	2.6	2,143	5.4	2.7	2,190	0.05
67	Energy Investors Funds	privately held corp.	10,804,244	10,600,234	1,773,190	1,810	3,981	5,121,799	0.00	0.3	0.7	948	0.3	0.8	966	2.0	3.9	2,270	0.00
68	PNM Resources	investor-owned corp.	10,761,878	7,363,587	5,921,895	3,138	10,829	7,327,466	0.01	0.6	2.0	1,362	0.9	2.9	1,990	1.1	3.6	2,228	0.00
69	Invenergy	privately held corp.	10,757,885	2,032,068	-	5	236	808,416	-	0.0	0.0	150	0.0	0.2	796	-	-	-	-
70	Seminole Electric Coop	cooperative	10,719,545	10,719,545	8,187,150	13,023	2,472	9,416,913	0.04	2.4	0.5	1,757	2.4	0.5	1,757	3.2	0.5	2,021	0.01
71	EDP	foreign-owned corp.	10,589,286	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Great River Energy	cooperative	10,539,482	10,400,311	10,217,042	19,831	11,019	11,748,732	0.28	3.8	2.1	2,229	3.8	2.1	2,259	3.9	2.1	2,274	0.05
73	Lower CO River Authority	state power authority	10,281,032	10,230,722	6,619,924	817	3,937	9,770,806	0.06	0.2	0.8	1,901	0.2	0.8	1,910	0.2	1.1	2,283	0.02
74	Sempra	investor-owned corp.	10,200,987	7,643,692	-	21	314	4,067,883	-	0.0	0.1	798	0.0	0.1	1,064	-	-	-	-
75	East Kentucky Power Coop	cooperative	10,198,488	10,063,427	9,571,037	9,154	4,378	10,762,201	0.04	1.8	0.9	2,111	1.8	0.9	2,139	1.9	0.9	2,175	0.01
76	BP	foreign-owned corp.	9,996,372	5,031,840	-	116	379	1,989,869	-	0.0	0.1	398	0.0	0.1	738	-	-	-	-
77	Energy Northwest	municipality	9,869,927	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	CLECO	investor-owned corp.	9,858,395	9,858,395	2,367,022	11,606	3,979	8,383,514	0.05	2.4	0.8	1,701	2.4	0.8	1,701	7.6	1.8	2,316	0.04
79	Integrys	investor-owned corp.	9,667,521	8,895,414	7,193,373	11,020	4,134	8,731,921	0.11	2.3	0.9	1,806	2.5	0.9	1,963	3.1	1.1	2,219	0.03
80	Brookfield	foreign-owned corp.	9,643,952	97,707	-	0	12	48,973	-	0.0	0.0	10	0.0	0.2	1,002	-	-	-	-
81	ALLETE	investor-owned corp.	9,500,264	8,071,626	8,053,971	7,505	5,859	9,399,853	0.15	1.6	1.2	1,979	1.8	1.3	2,329	1.8	1.4	2,331	0.04
82	El Paso Electric	investor-owned corp.	9,484,482	4,377,725	606,544	454	4,137	2,862,436	0.00	0.1	0.9	604	0.2	1.9	1,308	1.5	5.1	2,121	0.01
83	PUD No 1 of Chelan County	power district	9,472,316	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84	Buckeye Power	cooperative	9,368,635	9,368,635	9,252,128	10,318	5,501	9,651,743	0.14	2.2	1.2	2,060	2.2	1.2	2,060	2.2	1.2	2,070	0.03
85	Fortis Inc.	foreign-owned corp.	8,831,075	8,720,505	7,353,688	4,818	9,515	8,858,962	0.06	1.1	2.2	2,006	1.1	2.2	2,032	1.3	2.5	2,244	0.02
86	Entegra Power	privately held corp.	8,815,518	8,815,518	-	24	570	4,701,107	-	0.0	0.1	1,067	0.0	0.1	1,067	-	-	-	-
87	E.ON	foreign-owned corp.	8,803,155	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
88	Brazos Electric Power Coop	cooperative	8,759,213	8,759,213	1,619,926	680	880	4,881,041	0.01	0.2	0.2	1,114	0.2	0.2	1,114	0.8	0.5	2,187	0.01
89	PUD No 2 of Grant County	power district	8,396,060	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Austin Energy	municipality	8,275,421	4,971,154	3,374,624	302	2,377	4,699,655	0.03	0.1	0.6	1,136	0.1	1.0	1,891	0.2	1.1	2,294	0.02
91	The Carlyle Group	privately held corp.	7,920,117	7,713,288	870,298	747	1,855	3,868,926	0.00	0.2	0.5	977	0.2	0.4	1,003	1.7	2.6	1,975	0.00
92	TransCanada	foreign-owned corp.	7,903,568	6,135,305	-	301	1,692	3,492,053	-	0.1	0.4	884	0.1	0.6	1,138	-	-	-	-
93	Big Rivers Electric	cooperative	7,726,792	7,726,792	6,675,173	17,567	8,237	8,861,146	0.06	4.5	2.1	2,294	4.5	2.1	2,294	5.3	2.5	2,264	0.02
94	Avista	investor-owned corp.	7,341,169	2,938,713	1,408,978	1,110	1,704	2,253,597	0.01	0.3	0.5	614	0.8	1.2	1,534	1.6	2.4	2,303	0.01
95	Hoosier Energy	cooperative	7,254,121	7,219,643	7,035,256	11,865	2,794	7,619,955	0.04	3.3	0.8	2,101	3.3	0.8	2,107	3.4	0.8	2,134	0.01
96	TransAlta	foreign-owned corp.	7,187,115	6,767,888	6,675,766	3,037	7,540	7,963,448	0.07	0.8	2.1	2,216	0.9	2.2	2,353	0.9	2.3	2,369	0.02
97	Seattle City Light	municipality	7,079,168	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	International Paper	investor-owned corp.	6,940,561	1,507,971	289,295	-	2,216	725,261	-	-	0.6	209	-	2.9	962	-	9.0	1,657	-
99	NorthWestern Energy	investor-owned corp.	6,862,389	3,108,014	2,686,486	6,220	5,722	3,398,224	0.04	1.8	1.7	990	4.0	3.7	2,187	4.6	4.2	2,313	0.03
100	Sacramento Municipal Util Dist	municipality	6,845,151	5,520,901	-	12	132	2,331,113	-	0.0	0.0	681	0.0	0.0	844	-	-	-	-
		Total (in thousands)	3,488,800	2,311,317	1,399,403	2,822	1,426	1,954,826	0.02										
		Average								1.5	0.9	1,275	1.9	1.2	1,645	3.3	2.1	2,195	0.02
		Average (weighted by MWh)								1.7	0.9	1,171	2.4	1.2	1,688	4.0	1.9	2,178	0.03
		Median								1.1	0.8	1,275	1.2	1.2	1,789	2.6	1.9	2,203	0.02

* Breakdown of ownership categories provided in endnote 2 — privately/investor owned; public power; cooperative

Generation by Fuel Type

The 100 largest power producers in the U.S. accounted for 85 percent of the electricity produced in 2014. Coal accounted for 40 percent of the power produced by the 100 largest companies, followed by natural gas (26 percent), nuclear (22 percent), hydroelectric power (7 percent), oil (<1 percent), and non-hydroelectric renewables and other fuel sources such as non-biogenic municipal solid waste, tire-derived fuel, manufactured and waste gases, etc. (4 and 1 percent, respectively). Natural gas was the source of 38 percent of the power produced by smaller companies (i.e., those not within the top 100), followed by coal (30 percent), non-hydroelectric renewables/other (22 percent), hydroelectric power (5 percent), nuclear power (3 percent), and oil (2 percent).

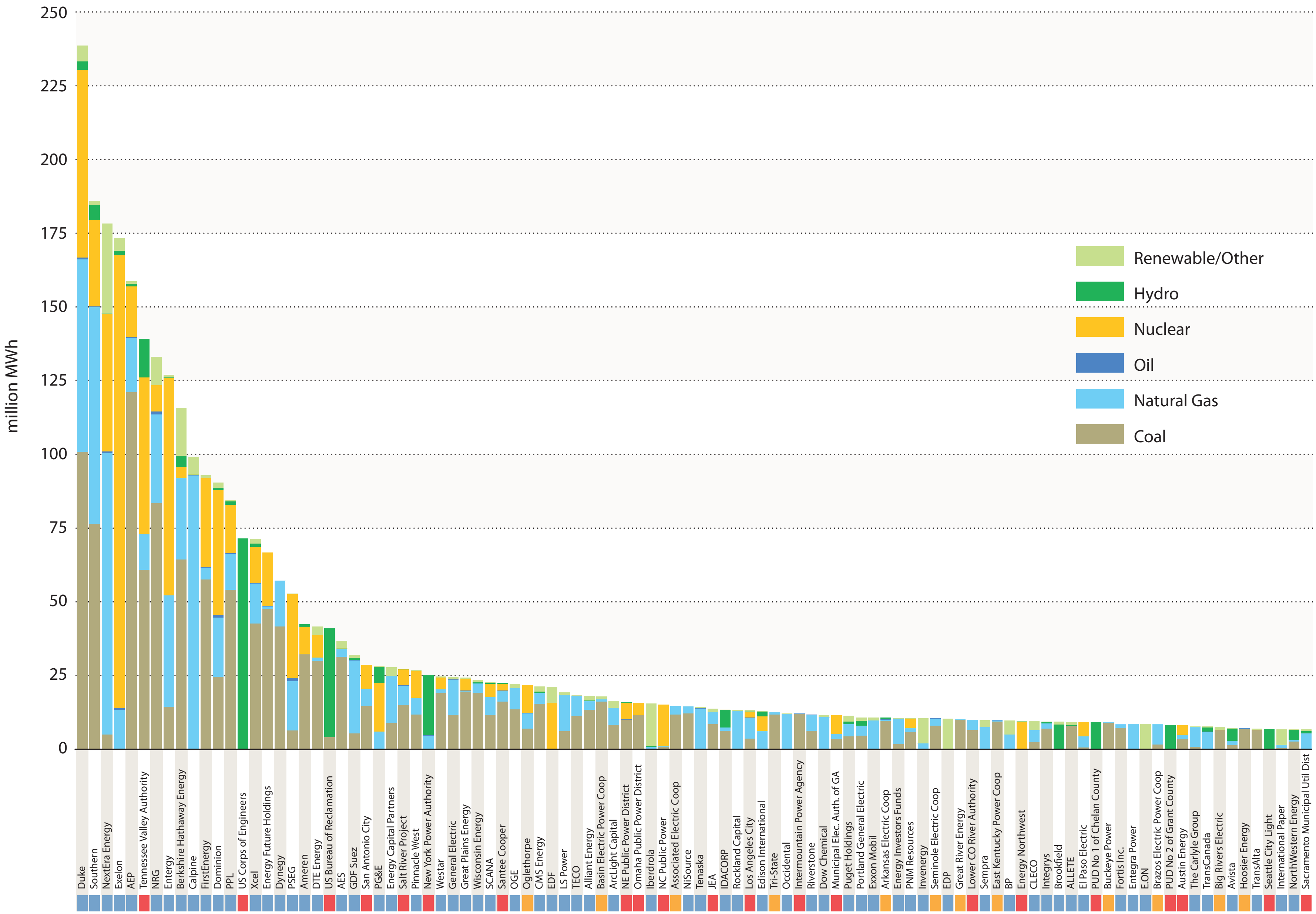
As a portion of total electric power production, the 100 largest producers accounted for 89 percent of all coal-fired power, 80 percent of natural gas-fired power, 46 percent of oil-fired power, 97 percent of nuclear power, 88 percent of hydroelectric power and 72 percent of non-hydroelectric renewable power.

Figure 10 illustrates the 2014 electricity generation by fuel for each of the 100 largest power producers. The generation levels, expressed in million megawatt hours, show production from facilities wholly and partially owned by each producer and reported to the EIA. Coal or nuclear accounted for over half of the output of the largest producers. The exceptions are a handful of generating companies whose assets are dominated by hydroelectric or natural gas-fired plants.

These data reflect the mix of generating facilities that are directly owned by the 100 largest power producers, not the energy purchases that some utility companies rely on to meet their customers' electricity needs. For example, some utility companies have signed long-term supply contracts for the output of renewable energy projects. In this report, the output of these facilities would be attributed to the owner of the project, not the buyer of the output.

FIGURE 10

Generation of 100 Largest Power Producers by Fuel Type (2014)



* Breakdown of ownership categories provided in endnote 2 privately/investor owned public power cooperative

Emissions Rankings

Table 2 shows the relative ranking of the 100 largest power producers by several measures—their contribution to total generation (MWh), total emissions and emission rates (emissions per unit of electricity output). These rankings help to evaluate and compare emissions performance.

Figures 11 through 14 illustrate SO_2, NOx, CO_2, and mercury emissions levels (expressed in tons for SO_2, NOx, and CO_2, and pounds for mercury) and emission rates for each of the 100 largest producers. These comparisons illustrate the relative emissions performance of each producer based on the company's ownership stake in power plants with reported emissions information. For SO_2 and NOx, the report presents comparisons of total emissions levels and rates for fossil fuel-fired facilities. For CO_2, the report presents comparisons of total emissions levels and rates for all generating sources (e.g., fossil, nuclear, and renewable). For mercury, the report presents comparisons of total emissions levels and rates for coal-fired generating facilities only.

The mercury emissions shown in this report were obtained from EPA's Toxic Release Inventory (TRI). The TRI contains facility-level information on the use and environmental release of chemicals classified as toxic under the Clean Air Act. While the TRI includes data on total facility chemical releases, this report uses the "air releases" section to calculate mercury emissions. Because coal plants are the primary source of mercury emissions within the electric industry, the mercury emissions and emission rates presented in this report reflect the emissions associated with each producer's fleet of coal plants only. Other toxic air pollutant emissions, such as hydrogen chloride and hydrogen fluoride (acid gases), are also reported to EPA under the TRI program. However, we have not included these air toxics because of uncertainties about the quality of the data submitted to EPA. We will continue to evaluate whether these pollutants might be included in future benchmarking efforts. In general, there is a strong correlation between SO_2 reductions and co-reductions in acid gas emissions.

The charts present both the total emissions by company as well as their average emission rates. The evaluation of emissions performance by both emission levels and emission rates provides a more complete picture of relative emissions performance than viewing these measures in isolation. Total emission levels are useful for understanding each producer's contribution to overall emissions loading, while emission rates are useful for assessing how electric power producers compare according to emissions per unit of energy produced when size is eliminated as a performance factor.

The charts illustrate significant differences in the total emission levels and emission rates of the 100 largest power producers. For example, the tons of CO_2 emissions range from zero to over 141 million tons per year. The NOx emission rates range from zero to 3.8 pounds of emissions per megawatt hour of generation. The total tons of emissions from any producer are influenced by the total amount of generation that a producer owns and by the fuels and technologies used to generate electricity.

TABLE 2

Company Rankings for 100 Largest Power Producers (2014)

in alphabetical order

		By Generation			By Tons of Emissions				By Emission Rates									
									All Generating Sources			Fossil Fuel Plants			Coal Plants			
Owner	Ownership Type*	Total	Fossil	Coal	SO_2	NOx	CO_2	Hg	SO_2	NOx	CO_2	SO_2	NOx	CO_2	SO_2	NOx	CO_2	Hg
AEP	investor-owned corp.	5	3	1	1	1	1	1	8	22	27	11	31	31	14	44	63	14
AES	investor-owned corp.	22	16	13	7	11	15	25	2	13	14	2	18	19	2	34	53	48
ALLETE	investor-owned corp.	81	68	45	48	49	53	30	36	30	12	41	39	2	52	54	8	13
Alliant Energy	investor-owned corp.	42	36	26	18	32	31	16	7	24	21	8	32	21	10	43	5	8
Ameren	investor-owned corp.	19	17	12	13	20	18	8	18	39	38	14	44	28	27	60	72	21
ArcLight Capital	privately held corp.	44	39	43	36	31	45	38	35	19	45	36	25	58	30	11	71	34
Arkansas Electric Coop	cooperative	66	56	38	23	29	46	23	4	3	10	6	6	14	12	14	41	6
Associated Electric Coop	cooperative	49	37	29	25	14	37	34	15	2	19	18	3	40	22	4	55	38
Austin Energy	municipality	90	82	65	76	70	73	58	73	58	54	74	50	39	75	64	15	41
Avista	investor-owned corp.	94	87	70	69	74	85	68	62	62	77	56	47	60	54	23	13	57
Basin Electric Power Coop	cooperative	43	35	19	28	19	23	13	27	5	4	33	9	4	45	21	3	4
Berkshire Hathaway Energy	privately held corp.	9	7	5	11	4	5	5	39	27	39	43	28	43	41	26	28	29
Big Rivers Electric	cooperative	93	69	51	30	41	54	49	6	7	1	10	14	5	13	22	21	43
BP	foreign-owned corp.	76	81	-	79	84	87	-	77	82	83	77	84	92	-	-	-	-
Brazos Electric Power Coop	cooperative	88	64	69	72	79	71	67	68	73	57	72	78	71	66	76	42	59
Brookfield	foreign-owned corp.	80	92	-	91	92	92	-	91	92	92	83	76	76	-	-	-	-
Buckeye Power	cooperative	84	61	40	43	53	51	32	26	32	9	30	45	22	44	61	69	25
Calpine	investor-owned corp.	10	6	-	74	46	13	-	79	78	72	80	81	85	-	-	-	-
CLECO	investor-owned corp.	78	60	67	40	64	57	51	24	47	28	29	57	50	3	41	9	11
CMS Energy	investor-owned corp.	38	30	21	16	27	22	15	3	28	18	4	38	27	4	45	29	10
Dominion	investor-owned corp.	12	15	15	20	23	16	22	52	66	75	46	59	59	46	62	58	40
Dow Chemical	investor-owned corp.	61	50	-	87	83	69	-	86	83	70	89	89	87	-	-	-	-
DTE Energy	investor-owned corp.	20	18	14	12	12	17	10	11	20	31	7	19	16	16	37	39	19
Duke	investor-owned corp.	1	1	2	4	2	2	11	40	46	55	38	46	56	32	42	66	56
Dynegy	investor-owned corp.	17	11	11	15	18	11	28	29	51	17	37	63	38	38	67	22	61
E.ON	foreign-owned corp.	87	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
East Kentucky Power Coop	cooperative	75	58	39	45	58	47	56	33	43	6	40	56	15	50	68	47	64
EDF	foreign-owned corp.	39	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Edison International	investor-owned corp.	56	76	-	84	89	82	-	84	89	82	86	91	86	-	-	-	-
EDP	foreign-owned corp.	71	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
El Paso Electric	investor-owned corp.	82	84	73	73	60	81	70	70	42	78	69	24	67	57	2	57	55
Energy Capital Partners	privately held corp.	26	20	41	55	57	28	61	59	71	48	63	72	63	63	70	16	68
Energy Future Holdings	privately held corp.	16	14	9	5	13	9	2	5	41	29	3	43	3	5	59	7	1
Energy Investors Funds	privately held corp.	67	53	68	64	63	70	72	60	50	64	65	62	77	47	6	20	74
Energy Northwest	municipality	77	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Entegra Power	privately held corp.	86	63	-	81	82	72	-	80	79	60	81	83	72	-	-	-	-
Entergy	investor-owned corp.	8	13	24	17	10	14	14	50	57	79	42	34	64	6	15	24	5
Exelon	investor-owned corp.	4	42	76	63	71	63	75	78	87	90	67	74	74	15	46	1	73
Exxon Mobil	investor-owned corp.	65	59	-	80	77	75	-	81	74	71	88	88	90	-	-	-	-
FirstEnergy	investor-owned corp.	11	10	7	10	5	8	7	28	18	42	23	10	23	33	17	56	39
Fortis Inc.	foreign-owned corp.	85	65	46	56	40	55	47	46	6	11	50	12	25	58	19	26	45
GDF Suez	foreign-owned corp.	23	19	58	31	48	30	35	47	69	59	49	70	70	7	58	60	9
General Electric	investor-owned corp.	31	22	32	8	16	29	20	1	12	40	1	22	62	1	8	64	7
Great Plains Energy	investor-owned corp.	32	29	16	26	28	21	18	32	33	24	31	36	12	43	53	46	26
Great River Energy	cooperative	72	54	36	27	36	43	21	9	9	2	15	16	8	26	32	19	3
Hoosier Energy	cooperative	95	74	49	39	67	59	54	16	48	7	20	60	18	29	72	54	54
Iberdrola	foreign-owned corp.	47	91	-	90	91	91	-	90	91	91	84	82	89	-	-	-	-
IDACORP	investor-owned corp.	53	72	55	46	45	60	37	42	35	58	32	20	26	39	27	35	28
Integrys	investor-owned corp.	79	62	47	42	61	56	36	25	44	22	26	51	32	34	65	37	24
Intermountain Power Agency	power district	59	46	28	57	15	42	71	51	1	13	58	1	30	69	7	73	75

* Breakdown of ownership categories provided in endnote 2 privately/investor owned public power cooperative

A ranking of 1 indicates the highest absolute number or rate in any column: the highest generation (MWh), highest emissions (tons), or highest emission rate (lb/MWh). A ranking of 100 indicates the lowest absolute number or rate in any column.

		By Generation			By Tons of Emissions				By Emission Rates									
									All Generating Sources			Fossil Fuel Plants			Coal Plants			
Owner	Ownership Type*	Total	Fossil	Coal	SO_2	NOx	CO_2	Hg	SO_2	NOx	CO_2	SO_2	NOx	CO_2	SO_2	NOx	CO_2	Hg
International Paper	investor-owned corp.	98	89	74	-	72	90	-	-	54	85	-	5	78	-	1	76	-
Invenergy	privately held corp.	69	88	-	89	87	89	-	89	85	88	85	77	91	-	-	-	-
JEA	municipality	52	41	42	29	30	40	46	21	11	23	25	23	45	25	12	52	49
Los Angeles City	municipality	55	51	63	66	62	61	45	66	56	56	68	64	65	70	35	61	15
Lower CO River Authority	state power authority	73	57	52	70	65	50	48	67	49	16	71	61	37	74	66	18	42
LS Power	privately held corp.	40	31	56	59	66	41	43	61	70	47	66	73	66	64	74	49	33
Municipal Elec. Auth. of GA	municipality	62	80	64	67	69	74	62	64	67	74	62	52	44	73	56	33	50
NC Public Power	municipality	48	90	71	68	80	88	69	69	81	89	24	30	6	40	50	17	52
NE Public Power District	power district	45	55	37	21	35	44	17	14	26	43	5	13	9	11	31	34	2
New York Power Authority	state power authority	29	83	-	82	86	86	-	85	88	87	79	85	82	-	-	-	-
NextEra Energy	investor-owned corp.	3	5	59	51	24	12	55	71	76	81	73	75	81	51	33	27	46
NiSource	investor-owned corp.	50	38	27	24	39	33	31	12	23	8	17	37	20	23	48	6	32
NorthWestern Energy	investor-owned corp.	99	86	66	53	50	80	53	31	15	62	13	2	10	18	5	12	23
NRG	investor-owned corp.	7	4	3	2	6	4	3	10	34	32	12	42	36	9	49	25	20
Occidental	investor-owned corp.	58	47	-	88	81	68	-	87	80	65	91	86	80	-	-	-	-
OGE	investor-owned corp.	36	25	25	19	21	24	26	17	16	26	21	26	41	17	29	11	22
Oglethorpe	cooperative	37	45	48	62	56	48	52	63	64	66	64	58	51	72	57	32	51
Omaha Public Power District	power district	46	49	34	22	34	39	24	13	21	35	9	21	11	19	39	45	12
PG&E	investor-owned corp.	25	78	-	85	90	83	-	88	90	86	87	90	84	-	-	-	-
Pinnacle West	investor-owned corp.	28	34	31	50	17	32	27	56	17	53	55	7	46	60	9	44	17
PNM Resources	investor-owned corp.	68	73	57	60	38	62	66	55	10	44	53	4	29	62	10	30	71
Portland General Electric	investor-owned corp.	64	67	60	47	54	66	65	37	36	52	35	40	53	28	30	40	67
PPL	investor-owned corp.	13	9	8	9	7	7	6	19	14	36	19	15	33	24	18	48	36
PSEG	investor-owned corp.	18	21	53	44	37	34	44	58	68	80	57	55	68	37	13	68	37
PUD No 1 of Chelan County	power district	83	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PUD No 2 of Grant County	power district	89	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Puget Holdings	privately held corp.	63	66	61	58	52	64	63	53	37	51	54	41	55	55	24	14	58
Riverstone	privately held corp.	60	48	54	34	55	49	64	23	40	30	28	54	52	20	52	23	66
Rockland Capital	privately held corp.	54	43	75	75	78	67	74	75	77	69	76	80	83	48	3	10	60
Sacramento Municipal Util Dist	municipality	100	79	-	86	88	84	-	83	86	76	90	92	88	-	-	-	-
Salt River Project	power district	27	24	22	54	22	25	33	57	25	41	61	27	47	68	25	43	44
San Antonio City	municipality	24	26	23	32	43	27	29	43	60	46	44	65	48	42	69	59	30
Santee Cooper	state power authority	35	28	20	52	47	26	50	54	59	34	59	66	42	67	73	67	65
SCANA	investor-owned corp.	34	33	33	33	42	36	59	38	53	50	39	53	57	35	55	75	69
Seattle City Light	municipality	97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Seminole Electric Coop	cooperative	70	52	44	37	68	52	57	22	63	25	27	69	49	31	75	70	63
Sempra	investor-owned corp.	74	71	-	83	85	77	-	82	84	73	82	87	73	-	-	-	-
Southern	investor-owned corp.	2	2	4	3	3	3	4	20	45	49	22	48	61	8	40	50	18
TECO	investor-owned corp.	41	32	35	38	51	35	60	41	55	33	47	67	54	49	71	65	70
Tenaska	privately held corp.	51	40	-	78	76	65	-	76	75	67	78	79	79	-	-	-	-
Tennessee Valley Authority	federal power authority	6	8	6	6	8	6	12	30	52	61	16	35	34	21	47	51	47
The Carlyle Group	privately held corp.	91	70	72	71	73	78	73	65	61	63	70	71	75	53	16	74	72
TransAlta	foreign-owned corp.	96	75	50	61	44	58	41	49	8	3	52	11	1	65	28	2	35
TransCanada	foreign-owned corp.	92	77	-	77	75	79	-	72	65	68	75	68	69	-	-	-	-
Tri-State	cooperative	57	44	30	49	26	38	42	45	4	5	48	8	13	59	20	38	53
US Bureau of Reclamation	federal power authority	21	85	62	65	59	76	40	74	72	84	60	17	17	71	36	62	16
US Corps of Engineers	federal power authority	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Westar	investor-owned corp.	30	27	18	35	25	19	19	44	31	20	45	33	7	56	51	4	27
Wisconsin Energy	investor-owned corp.	33	23	17	41	33	20	39	48	38	15	51	49	24	61	63	31	62
Xcel	investor-owned corp.	15	12	10	14	9	10	9	34	29	37	34	29	35	36	38	36	31

* Breakdown of ownership categories provided in endnote 2 privately/investor owned public power cooperative

NOx and SO_2 Emissions Levels and Rates

Figures 11 and 12 display NOx and SO_2 emission levels and emission rates for fossil fuel-fired generating sources owned by each company.

"Fossil only" emission rates are calculated by dividing each company's total NOx and SO_2 emissions from fossil-fired power plants by its total generation from fossil-fired power plants. Companies with significant coal-fired generating capacity have the highest total emissions of SO_2 and NOx because coal contains higher concentrations of sulfur than natural gas and oil and coal plants generally have higher NOx emission rates.

Figures 11 and 12 illustrate wide disparities in the "fossil only" emission levels and emission rates of the 100 largest power producers. The largest amount of fossil generation from a single company totaled 171 million megawatt hours, 8 of the 100 largest producers had no fossil generation, and:

- NOx emission rates range from 0.02 pounds per megawatt hour to 3.8 pounds per megawatt hour, (0.002–3.8 lb/MWh, if generation from all fuel types is considered) and NOx emissions range from 12 to 111,446 tons;
- SO_2 emission rates range from 0.001 pounds per megawatt hour to 10.2 pounds per megawatt hour, (0.0001–9.9 lb/MWh, if generation from all fuel types is considered) and SO_2 emissions range from 0.2 to 320,894 tons.

FIGURE 11

Fossil Fuel - NOx Total Emissions and Emission Rates (2014)

Total emissions (thousand tons) and emission rates (lb/MWh) from fossil fuel generating facilities

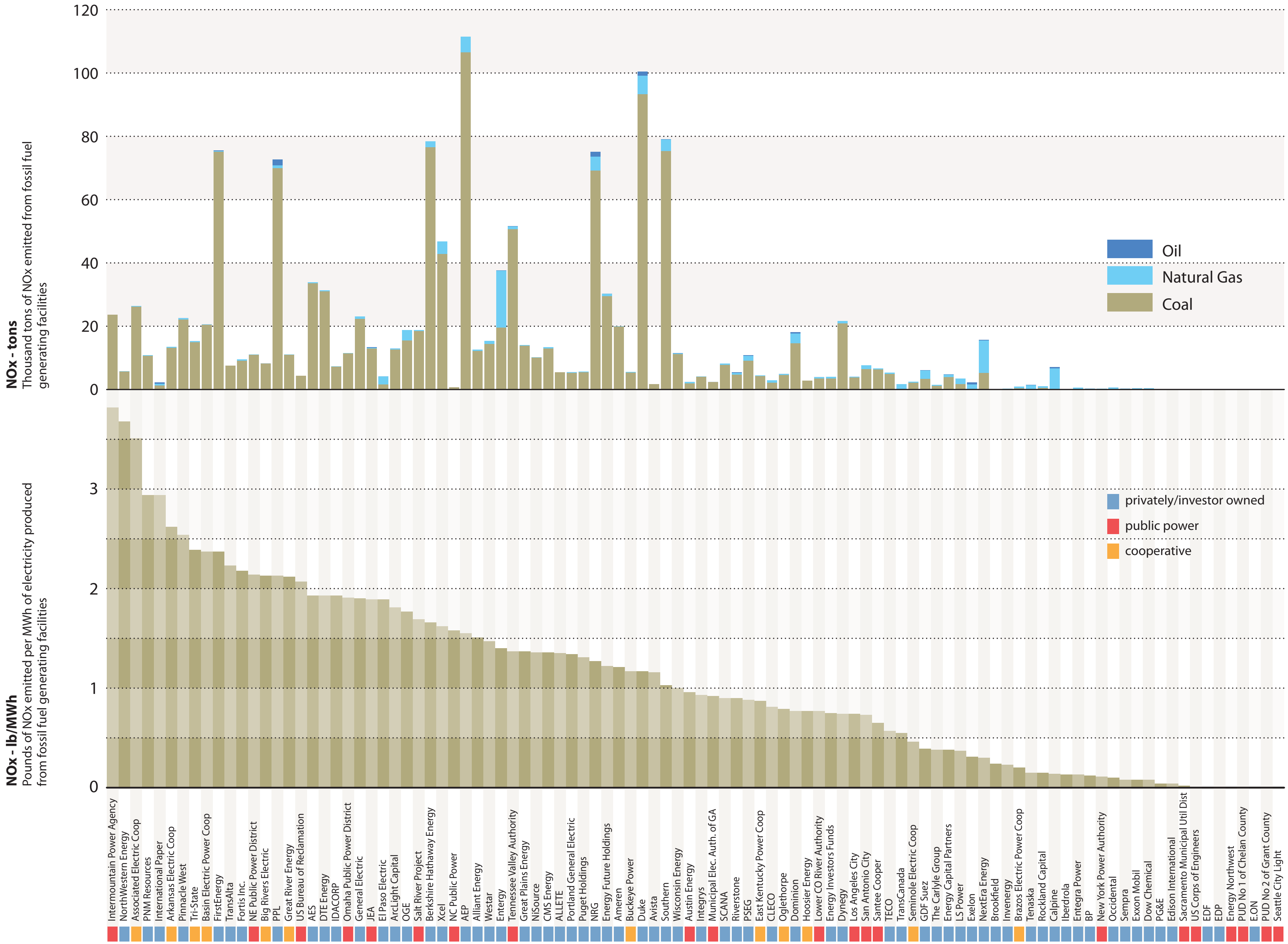
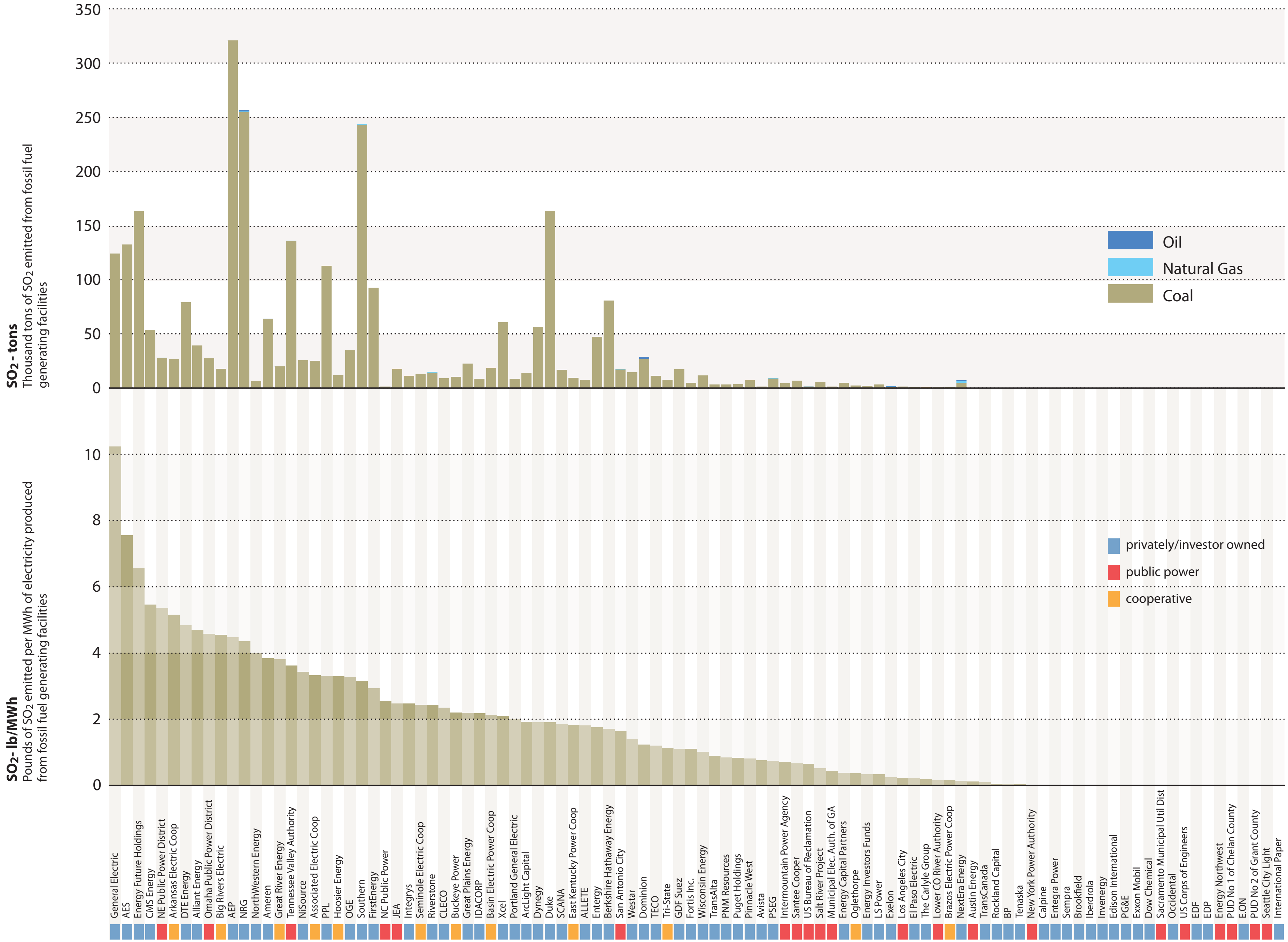


FIGURE 12

Fossil Fuel - SO_2 Total Emissions and Emission Rates (2014)

Total emissions (thousand tons) and emission rates (lb/MWh) from fossil fuel generating facilities



CO_2 Emission Levels and Rates

Figure 13 displays total CO_2 emission levels from coal, oil, and natural gas combustion and emission rates based on all generating sources owned by each company.

"All-source" emission rates are calculated by dividing each company's total CO_2 emissions by its total generation. In most cases, producers with significant non-emitting fuel sources, such as nuclear, hydroelectric and wind power, have lower all-source emission rates than producers owning primarily fossil fuel power plants. Among the 100 largest power producers:

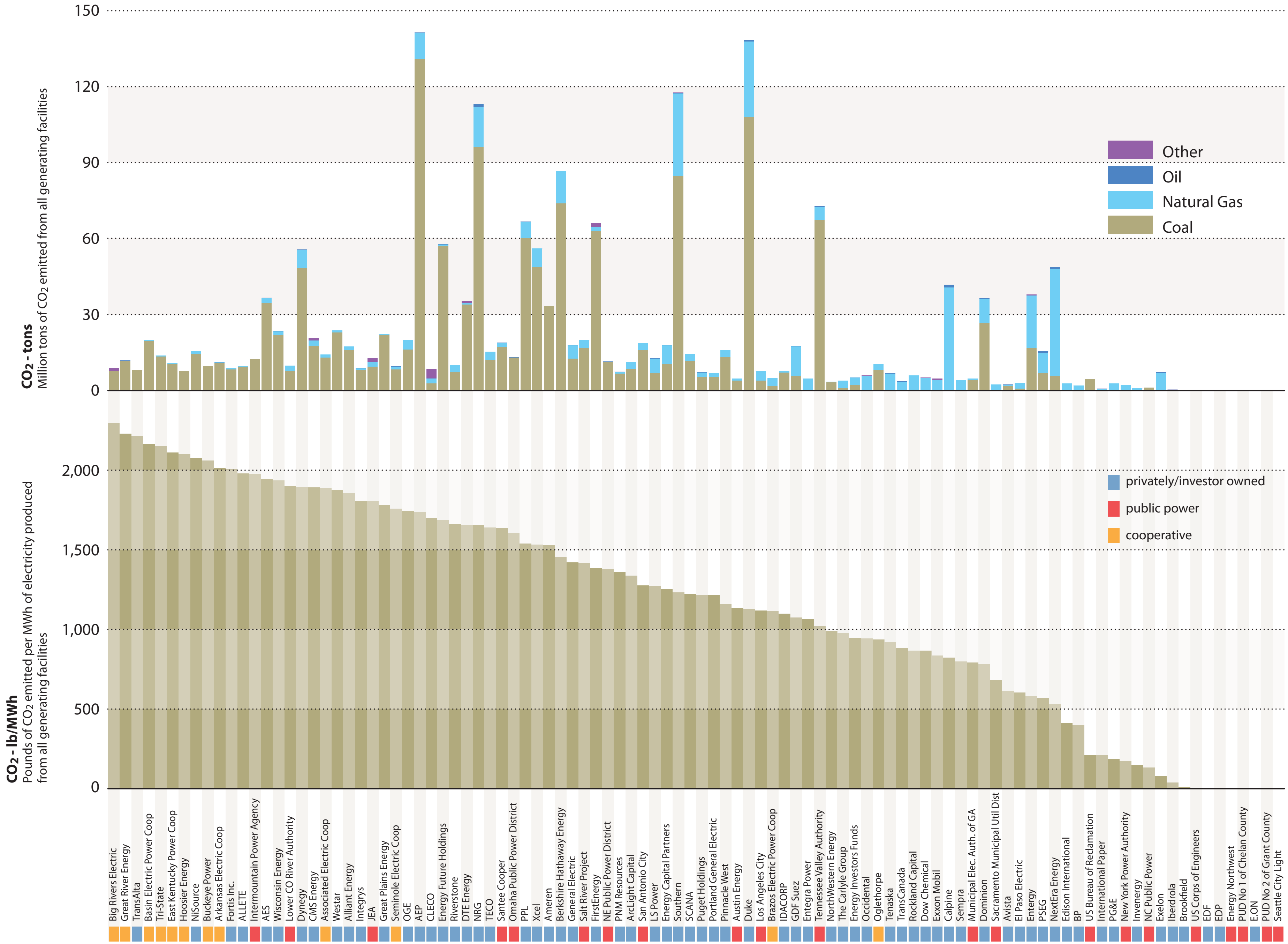
- Coal-fired power plants are responsible for 78 percent of CO_2 emissions.
- Natural gas-fired power plants are responsible for 21 percent of CO_2 emissions.
- Oil-fired power plants are responsible for 0.4 percent of CO_2 emissions.

Figure 13 illustrates wide disparities in the "all-source" emission levels and emission rates of the 100 largest power producers. Their total electric generation varies from 6.8 million megawatt hours to 245 million megawatt hours, their CO_2 emissions range from 0 to 141.4 million tons, and their CO_2 emission rates range from 0 pounds per megawatt hour to 2,294 pounds per megawatt hour.

FIGURE 13

All Source - CO_2 Total Emissions and Emission Rates (2014)

Total emissions (million tons) and emission rates (lb/MWh) from all generating facilities



Mercury Emission Levels and Rates

Figure 14 displays total mercury emission levels and emission rates from coal-fired power plants.

In 2012, EPA finalized the Mercury and Air Toxics Standards (MATS), regulating emissions of mercury and other hazardous air pollutants from coal- and oil-fired electric generating units. The standards went into effect April 16, 2015, although there is still a pending legal challenge to the rule. Also, many coal units obtained a one-year extension to the initial compliance date. The differences in mercury emission rates seen in the following figures are due to the mercury content and type of coal used, and the effect of control technologies designed to lower SO_2, NOx, and particulate emissions. In recent years, a significant amount of coal-fired capacity has also installed mercury controls to comply with MATS and state mercury rules.

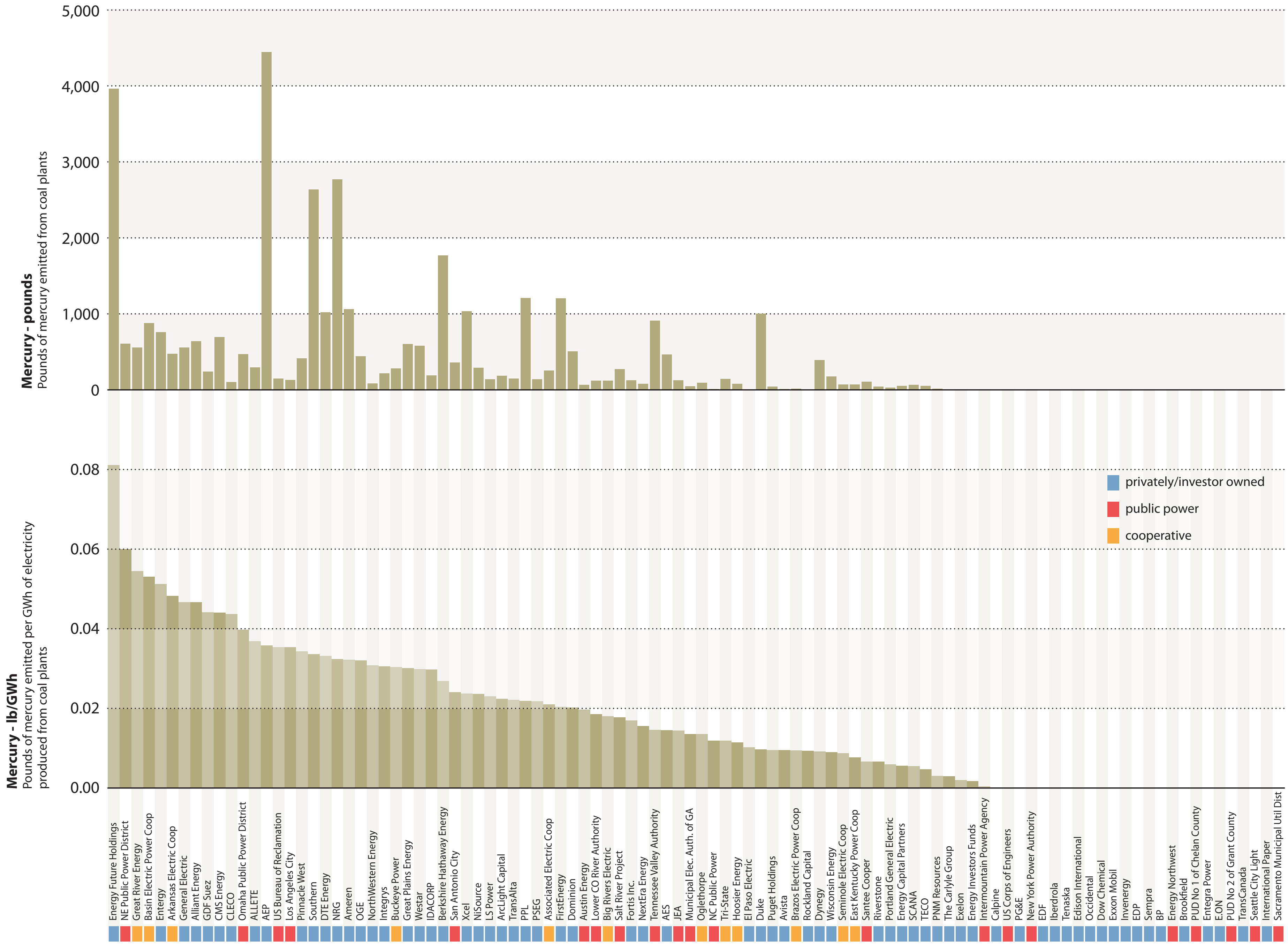
Coal mercury emissions from the top 100 power producers range from less than 1 pound to 4,448 pounds, and coal mercury emission rates range from 0.0003 pound per gigawatt hour (a gigawatt hour is 1,000 megawatt-hours) to 0.081 pound per gigawatt hour.

FIGURE 14

Coal - Mercury Emission Rates and Total Emissions (2014)

Emission rates (lb/GWh) and total emissions (pounds) from coal plants

1 gigawatt-hour (GWh) = 1,000 MWh



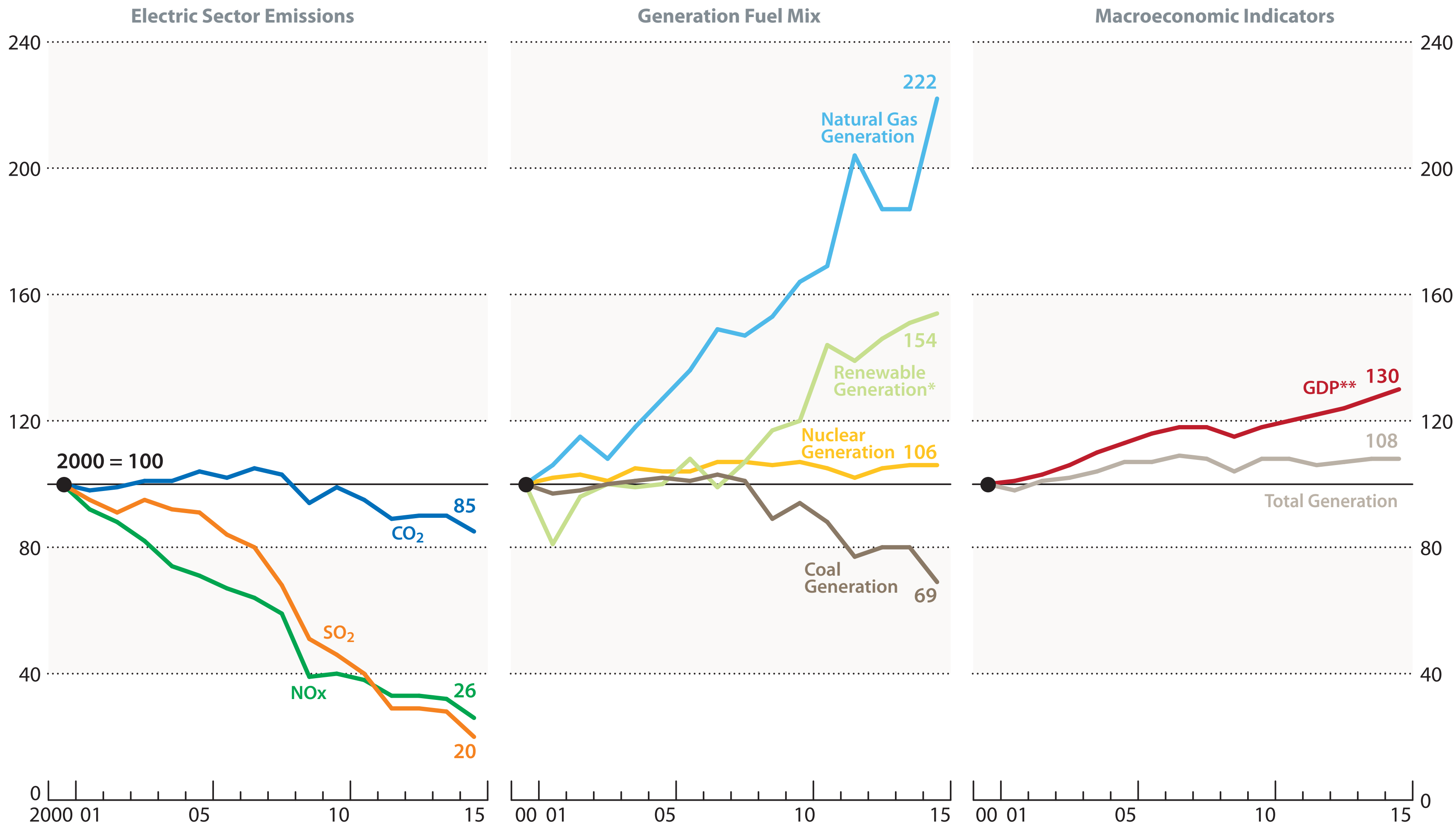
Trends Analysis

The electric power sector has made significant progress in terms of reducing its NOx and SO_2 emissions over the past several decades. In 2014, power plant NOx and SO_2 emissions were 75 percent and 80 percent lower, respectively, than they were in 1990 when Congress passed major amendments to the Clean Air Act. Large reductions in mercury emissions have also been realized, with 2014 emissions 55 percent below 2000 emissions. Less progress has been made in terms of reducing CO_2 emissions. In 2014, power plant CO_2 emissions were 14 percent higher than 1990 levels. However, as illustrated in Figure 15, in recent years CO_2 emissions from power plants have declined, with 2014 emissions 12 percent lower than emissions in 2008. Preliminary data suggest this trend continued into 2015, with emissions decreasing 6 percent from 2014 to 2015 to their lowest levels in 22 years.

Figure 15 plots the trends in power plant NOx, SO_2, and CO_2 emissions since 2000 (indexed 12-month totals). Figure 15 also plots the total electricity generation by fuel type, as well as gross domestic product (GDP). The electric industry has cut its NOx and SO_2 emissions even as overall electricity generation and GDP have increased. In the wake of the recent economic recession, stronger pollution standards, the low natural gas price environment, and declining overall electricity demand, power plant emissions have declined significantly. Emissions have leveled off in recent years, but are expected to decline further in response to coal plant retirements, the installation of pollution controls at coal-fired power plants, and low natural gas prices. New environmental policies, including the Clean Power Plan, are also expected to contribute to the overall trend in declining electric sector emissions. Between 2012 and 2014, CO_2 emissions were basically flat.

FIGURE 15

Annual Electric Sector Trends and Macroeconomic Indicators
(Indexed: 2000 = 100)

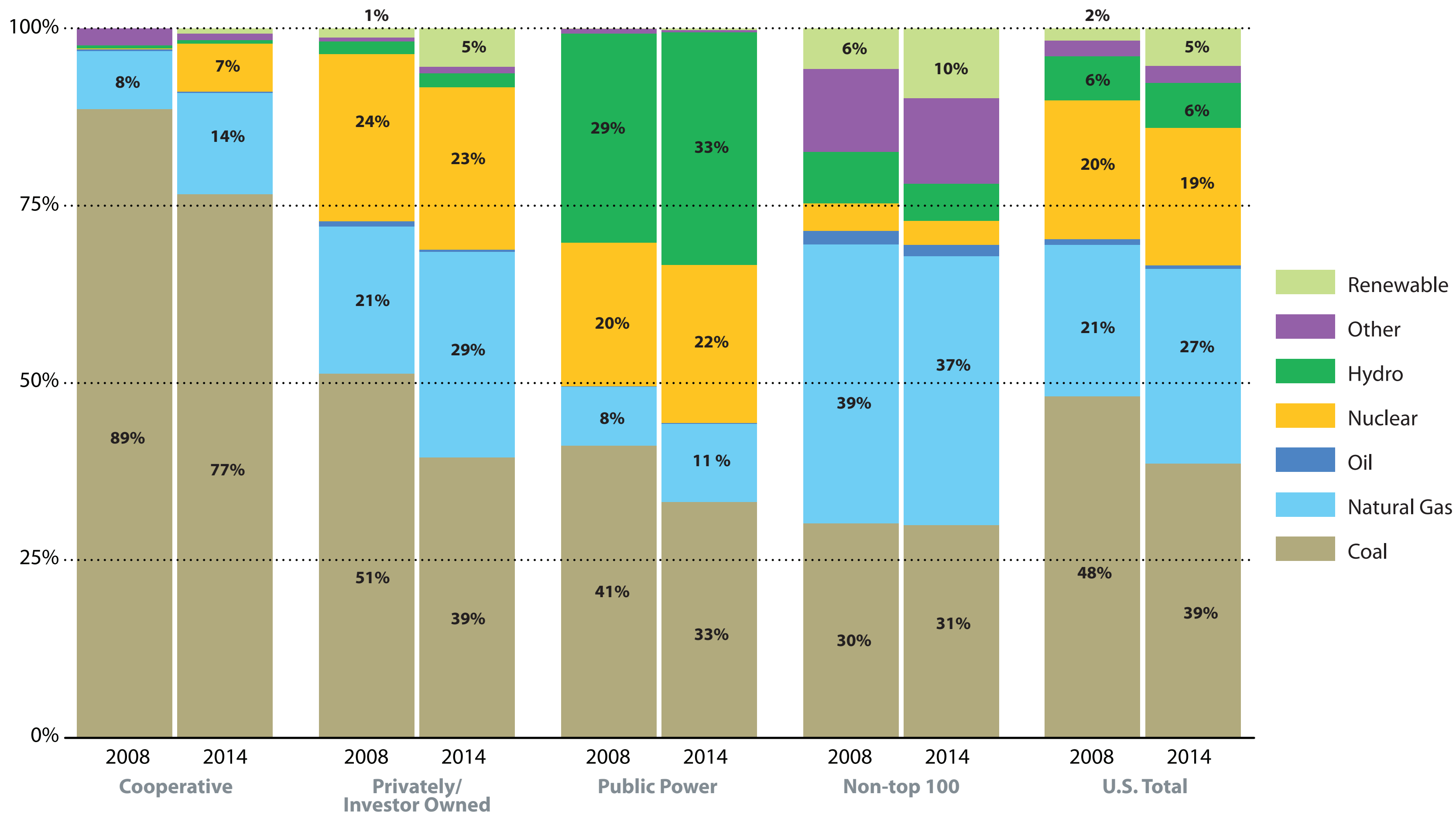


*INCLUDES HYDROELECTRIC, WIND, SOLAR, BIOMASS, GEOTHERMAL AND OTHER RENEWABLE SOURCES.
**GDP IN CHAINED 2009 DOLLARS.

As discussed earlier, there have been major shifts in the fuels used to generate electricity in the U.S. Figure 16 shows that coal-fired generation decreased between 2008 and 2014 for most types of producers while electricity from natural gas and renewable energy resources increased. Smaller producers outside the top 100 saw less change across their generation portfolios. Across all producers, coal's share of total generation decreased from 48 to 39 percent while natural gas' share increased from 21 to 27 percent. Renewable generation also increased to represent 5 percent of total generation, while nuclear's contribution remained fairly constant.

FIGURE 16

Change in Portfolio Mix by Ownership Category
(% Share of Total Generation)

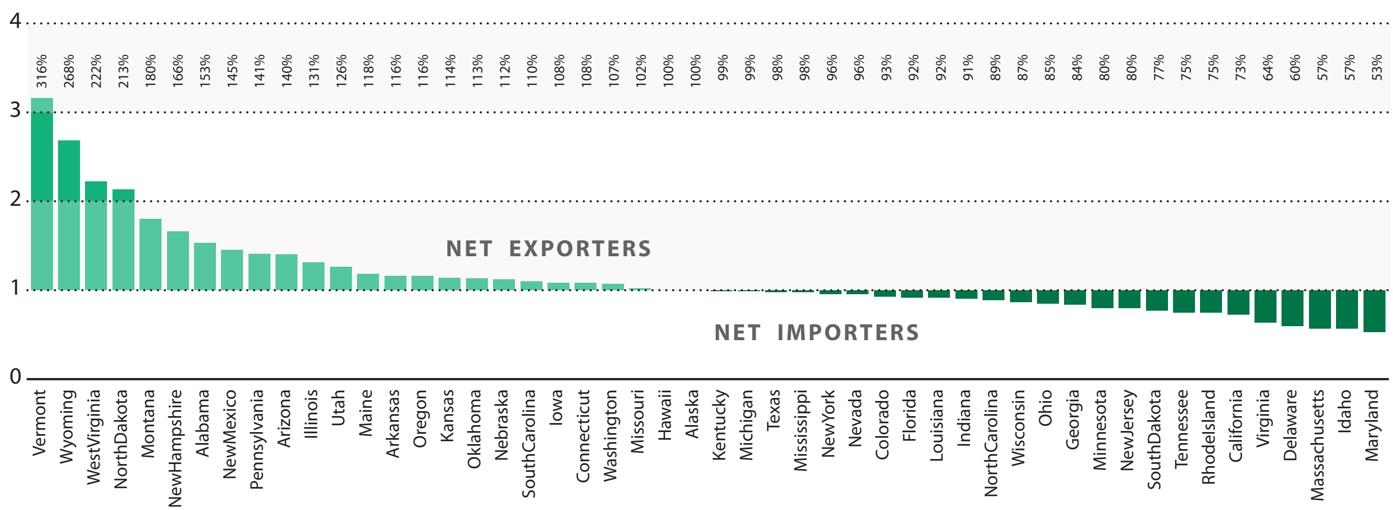


State-by-State Emissions Summary

Figure 18 summarizes CO_2 emissions from power plants on a state-by-state basis. Texas, Florida, and Indiana had the highest total CO_2 emissions in the U.S. in 2014. Vermont, Idaho, and Maine have the lowest total CO_2 emissions. Figure 18 also presents the average CO_2 emission rates for each state, including all source CO_2 emission rates, fossil CO_2 emission rates, and coal-only CO_2 emission rates. While Texas ranks first in terms of total emissions, it ranks 21st in terms of its all-source CO_2 emission rate. Kentucky, Wyoming, and West Virginia have the highest all-source CO_2 emission rates because of their heavy reliance on coal for electricity generation. States also vary in terms of their import and export of electricity. Florida, for example, produces virtually all of the electricity that it generates with limited imports. West Virginia and North Dakota, in contrast, are large exporters of electricity. Figure 17 summarizes the net imports or exports of electricity by state.

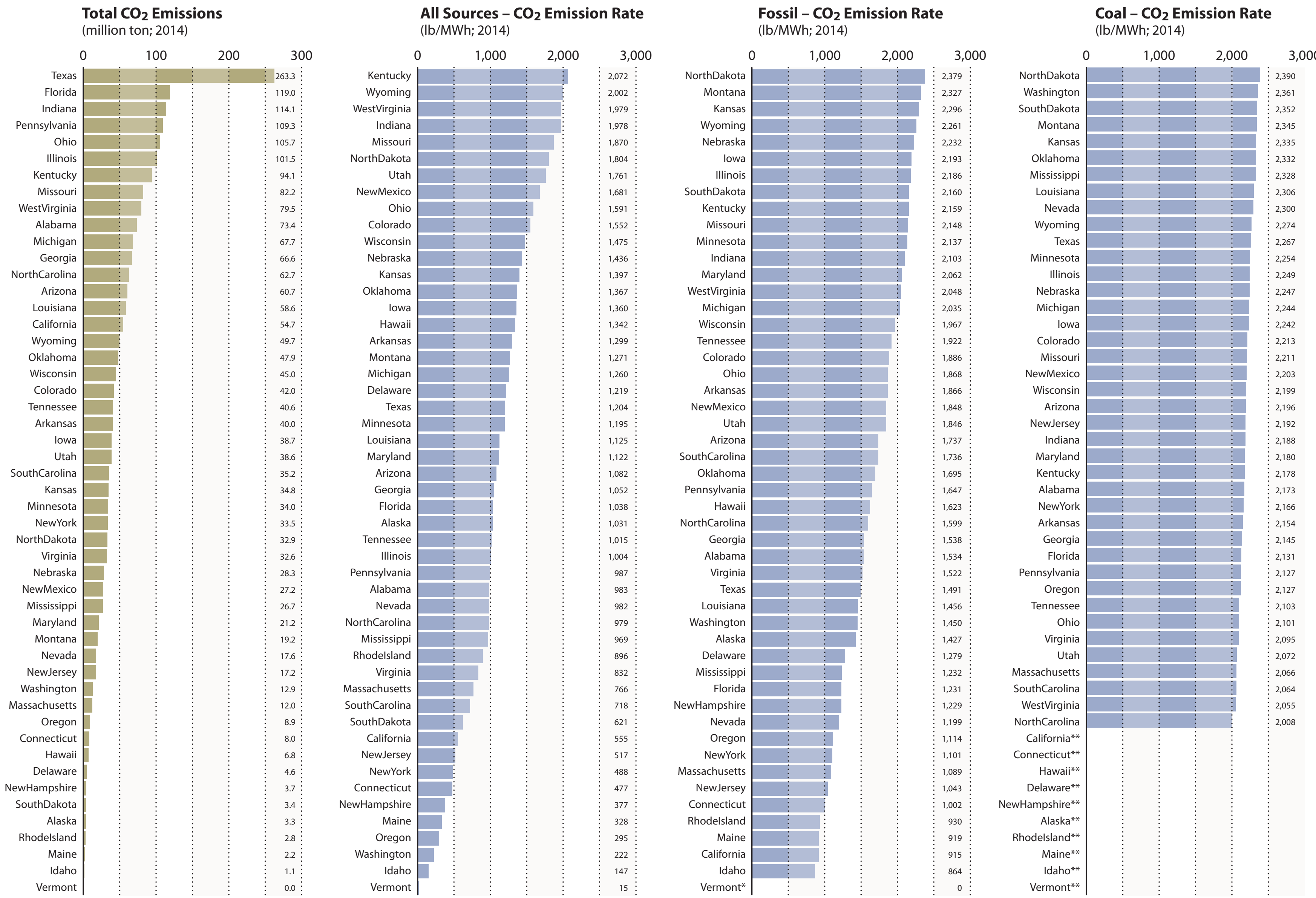
FIGURE 17

Electricity Exporters/Importers
(Net Trade Index; 2013)



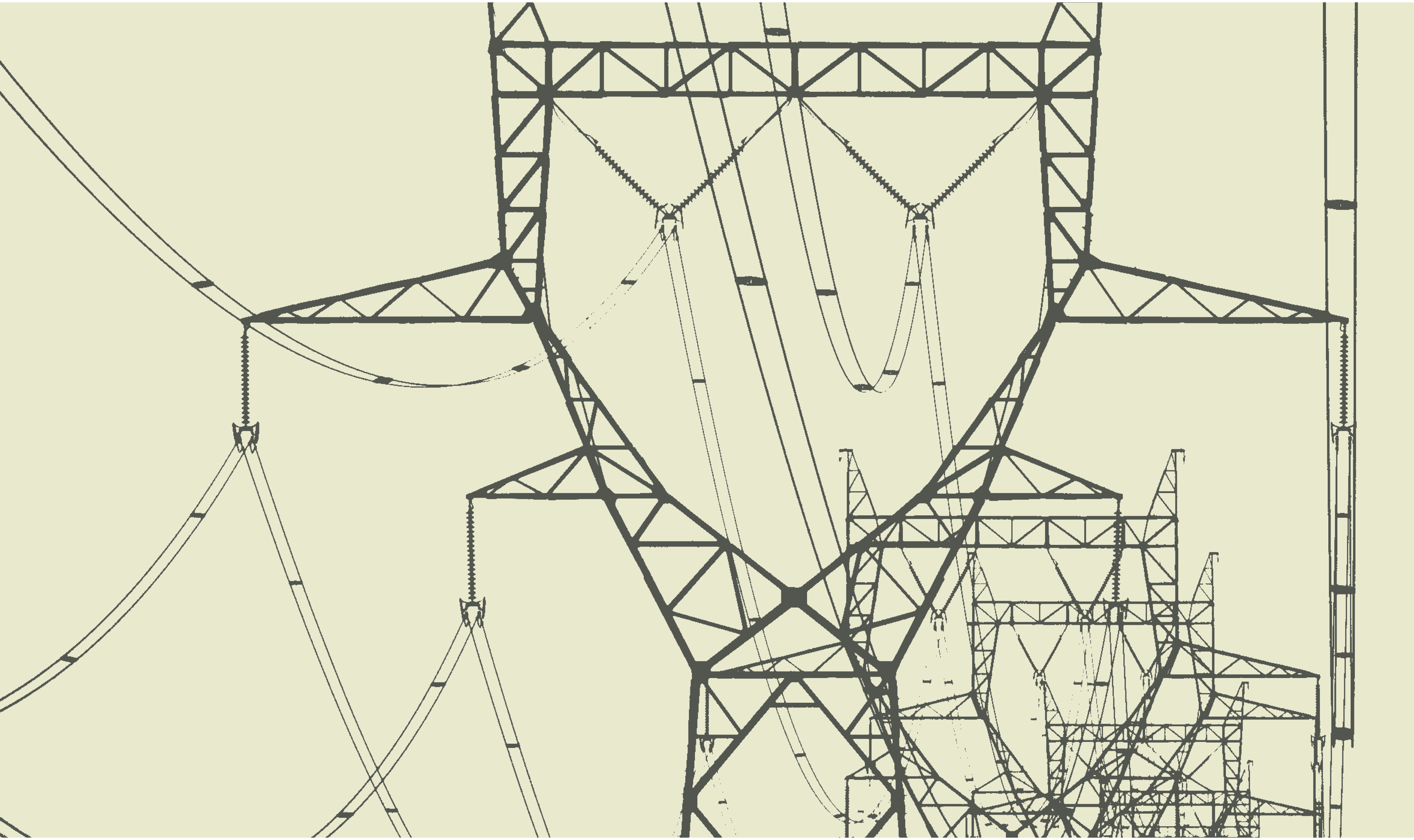
% : TOTAL IN-STATE SUPPLY OF ELECTRICITY AS % SHARE OF TOTAL IN-STATE CONSUMPTION NEEDS; IN-STATE SUPPLY INCLUDES INTERNATIONAL IMPORTS.

FIGURE 18



* FOSSIL-FIRED GENERATION OUTPUT IN THE STATE OF VERMONT IS TOO LOW TO CALCULATE A MEANINGFUL EMISSION RATE.

** COAL-FIRED GENERATION OUTPUT IN THESE STATES IS TOO LOW TO CALCULATE A MEANINGFUL EMISSION RATE.



Appendix A
Data Sources, Methodology and Quality Assurance

This report examines the air pollutant emissions of the 100 largest electricity generating companies in the United States based on 2014 electricity generation, emissions, and ownership data. The report relies on publicly-available information reported by the U.S. Energy Information Administration (EIA), U.S. Environmental Protection Agency (EPA), Securities and Exchange Commission (SEC), state environmental agencies, company websites, and media articles. Emission data may include revisions to 2014 data that companies were in the process of submitting or have already submitted to EPA at the time of publication of this report.

Data Sources

The following public data sources were used to develop this report:

EPA AIR MARKETS PROGRAM DATA (AMP): EPA's Air Markets Program Data account for almost all of the SO_2 and NOx emissions, and about 20 percent of the CO_2 emissions analyzed in this report. These emissions were compiled using EPA's on-line emissions database available at http:// http://ampd.epa.gov/ampd/.

EPA TOXIC RELEASE INVENTORY (TRI): Power plants and other facilities are required to submit reports on the use and release of certain toxic chemicals to the TRI. The 2014 mercury emissions used in this report are based on TRI reports submitted by facility managers and are available at http:// http://iaspub.epa.gov/triexplorer/tri_release.chemical.

EIA FORMS 923 POWER PLANT DATABASES (2014): EIA Form 923 provided almost all of the generation data analyzed in this report. EIA Form 923 provides data on the electric generation and heat input by fuel type for utility and non-utility power plants. The heat input data was used to calculate approximately 80 percent of the CO_2 emissions analyzed in this report. The form is available at http://www.eia.doe.gov/cneaf/electricity/page/eia906_920.html.

EIA FORM 860 ANNUAL ELECTRIC GENERATOR REPORT (2014): EIA Form 860 is a generating unit level data source that includes information about generators at electric power plants, including information about generator ownership. EIA Form 860 was used as the primary source of power plant ownership for this report. The form is available at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

EPA U.S.INVENTORY OF GREENHOUSE GAS EMISSIONS AND SINKS (2015): EPA's U.S.Inventory of Greenhouse Gas Emissions and Sinks report provides in Annex 2 heat contents and carbon content coefficients of various fuel types.This data was used in conjunction with EIA Form 923 to calculate approximately 20 percent of the CO2 emissions analyzed in this report.Annex 2 is available at https://www3.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2016-Annex-2-Emissions-Fossil-Fuel-Combustion.pdf.

Plant Ownership

This report aims to reflect power plant ownership as of December 31, 2014. Plant ownership data used in this report are primarily based on the EIA-860 database from the year 2014. EIA-860 includes ownership information on generators at electric power plants owned or operated by electric utilities and non-utilities, which include independent power producers, combined heat and power producers, and other industrial organizations. It is published annually by EIA.

For the largest 100 power producers, plant ownership is further checked against self-reported data from the producer's 10-K form filed with the SEC, listings on their website, and other media sources. Ownership of plants is updated based on the most recent data available. Consequently, in a number of instances, ultimate assignment of plant ownership in this report differs from EIA-860's reported ownership. This primarily happens when the plant in question falls in one or more of the categories listed below:

1. It is owned by a limited liability partnership of shareholders of which are among the 100 largest power producers.
2. The owner of the plant as listed in EIA-860 is a subsidiary of a company that is among the 100 largest power producers.
3. It was sold or bought during the year 2014. Because form 10-K for a particular year is usually filed by the producer in the first quarter of the following year, this report assumes that ownership as reported in form 10-K is more accurate.

Publicly available data do not provide a straightforward means to accurately track lease arrangements and power purchase agreements. Therefore, in order to apply a standardized methodology to all companies, this report allocates generation and any associated emissions according to reported asset ownership as of December 31, 2014.

Identifying “who owns what” in the dynamic electricity generation industry is probably the single most difficult and complex part of this report. In addition to the categories listed above, shares of power plants are regularly traded and producers merge, reorganize, or cease operations altogether. While considerable effort was expended in ensuring the accuracy of ownership information reflected in this report, there may be inadvertent errors in the assignment of ownership for some plants where public information was either not current or could not be verified.

Generation Data and Cogeneration Facilities

Plant generation data used in this report come from EIA Form 923.

Cogeneration facilities produce both electricity and steam or some other form of useful energy. Because electricity is only a partial output of these plants, their reported emissions data generally overstate the emissions associated with electricity generation. Generation and emissions data included in this report for cogeneration facilities have been adjusted to reflect only their electricity generation. For all such cogeneration facilities emissions data were calculated on the basis of heat input of fuel associated with electricity generation only. Consequently, for all such facilities EIA Form 923, which report a plant’s total heat input as well as that which is associated with electricity production only, was used to calculate their emissions.

NOx and SO_2 Emissions

The EPA AMP database collects and reports SO_2 and NOx emissions data for nearly all major power plants in the U.S. Emissions information reported in the AMP database is collected from continuous emission monitoring (CEM) systems. SO_2 and NOx emissions data reported to the AMP account for all of the SO_2 and NOx emissions assigned to the 100 largest power producers in this report.

The AMP database collects and reports SO_2 and NOx emissions data by fuel type at the boiler level. This report consolidates this data at the generating unit and plant levels. In the case of jointly owned plants, because joint ownership is determined by producer's share of installed capacity, assignment of SO_2 and NOx emissions to the producers on this basis implicitly assumes that emission rates are uniform across the different units. This may cause producers to be assigned emission figures that are slightly higher or lower than their actual shares.

The appointment of NOx emissions between coal and natural gas at boilers that can burn both fuels may in certain instances slightly overstate coal's share of the emissions. This situation is likely to arise when a dual-fuel boiler that is classified as "coal-fired" within AMP burns natural gas to produce electricity in substantial amounts. In most years there would be very little economic reason to make this switch in a boiler that is not part of a combined cycle setup. But low natural gas prices in 2014 led to a small number of boilers switching to natural gas for most or a large part of their electricity output. Because AMP datasets do not make this distinction, apportioning emissions based on the fuel-type of the boiler would increase coal's share of emissions.

SO_2 and CO_2 emissions are mostly not affected by this issue. Natural gas emits virtually no SO_2. CO_2 emissions can be calculated from the heat input data reported in EIA Form 923, which allows for the correct apportionment of emissions between coal and natural gas.

CO_2 Emissions

A majority of CO_2 emissions used in this report were calculated using heat input data from EIA Form 923 and carbon content coefficients of various fuel types provided by EPA. Table A.1 shows the carbon coefficients used in this procedure. Non-emitting fuel types, whose carbon coefficients are zero, are not shown in the table. CO_2 emissions reported through the EPA AMP account for a small share of the CO_2 emissions used in this report.

The datasets report heat input and emissions data by fuel type at either the prime mover or boiler level. This report consolidates that data at the generating unit and plant levels. In the case of jointly owned plants, because joint ownership is determined by producer's share of installed capacity, assignment of CO_2 emissions to the producers on this basis implicitly assumes that emission rates are uniform across the different units. This may cause producers to be assigned emission figures that are slightly higher or lower than their actual shares.

Mercury Emissions

Mercury emissions data for coal power plants presented in this report were obtained from EPA's Toxic Release Inventory (TRI). Mercury emissions reported to the TRI are based on emission factors, mass balance calculations, or data monitoring. The TRI contains facility-level information on the use and environmental release of chemicals classified as toxic under the Clean Air Act. The TRI contains information on all toxic releases from a facility; mercury emissions in this report are based on air releases only. Because coal plants are the primary source of mercury emissions within the electric industry, the mercury emissions and emission rates presented in this report reflect the emissions associated with each producer's fleet of coal plants only.

TABLE A.1

Carbon Content Co-efficients by Fuel Type
From Table A-40 (in Annex 2 of GHG Inventory 2016)

FUEL TYPE	CARBON CONTENT COEFFICIENTS (Tg Carbon/Qbtu)
COAL	
Anthracite Coal	28.28
Bituminous Coal	25.44
Sub-bituminous Coal	26.50
Lignite Coal	26.65
Waste/Other Coal (includes anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)	26.05
Coal-based Synfuel (including briquettes, pellets, or extrusions, which are formed by binding materials or processes that recycle materials)	25.34
Coal-based Synfuel Gas	18.55
OIL	
Distillate Fuel Oil (Diesel, No. 1, No. 2, and No. 4 Fuel Oils)	20.17
Jet Fuel	19.70
Kerosene	19.96
Residual Fuel Oil (No. 5, No. 6 Fuel Oils, and Bunker C Fuel Oil)	20.48
Waste/Other Oil (including Crude Oil, Liquid Butane, Liquid Propane, Oil Waste, Re-Refined Motor Oil, Sludge Oil, Tar Oil, or other petroleum-based liquid wastes)	20.55
Petroleum Coke	27.85
GAS	
Natural Gas	14.46
Blast Furnace Gas	18.55
Other Gas	18.55
Gaseous Propane	14.46

Appendix B
Fuel Mix of the
Top-100 Power Producers

Table B.1 shows the 2014 fuel-mix for each of the 100 largest power producers. The share of each major fuel type –coal, gas, oil, nuclear, hydro, and renewable / other – is shown as a percentage share of total generation from facilities wholly and partially owned by each producer and reported to the EIA.

"Renewable / Other" comprises mostly generation from wind, solar, biomass, and geothermal, along with some small contributions from other miscellaneous fuel sources, including non-biogenic municipal solid waste, tire-derived fuel, manufactured and waste gases, etc.

Figure 10 in the main body of the report presents a graphical illustration of the data in Table B.1.

TABLE B.1

Fuel Mix of 100 Largest Power Producers

in order of 2014 generation

Rank	Owner	Ownership Type*	Total (million MWh)	Coal	Natural Gas	Oil	Nuclear	Hydro	Renewable/ Other
1	Duke	investor-owned corp.	245.0	42%	27%	0.2%	27%	1%	2%
2	Southern	investor-owned corp.	190.9	41%	40%	0.1%	16%	3%	1%
3	NextEra Energy	investor-owned corp.	183.0	3%	54%	0.3%	26%	0%	17%
4	Exelon	investor-owned corp.	178.0	0%	8%	0.2%	89%	1%	2%
5	AEP	investor-owned corp.	162.9	76%	12%	0.2%	11%	1%	1%
6	Tennessee Valley Authority	federal power authority	142.9	44%	9%	0.2%	38%	9%	0%
7	NRG	investor-owned corp.	136.7	63%	23%	0.8%	7%	0%	7%
8	Entergy	investor-owned corp.	130.3	11%	30%	0.0%	58%	0%	1%
9	Berkshire Hathaway Energy	privately held corp.	118.9	56%	24%	0.1%	3%	3%	14%
10	Calpine	investor-owned corp.	101.8	0%	94%	0.4%	0%	0%	6%
11	FirstEnergy	investor-owned corp.	95.4	62%	4%	0.2%	33%	0%	1%
12	Dominion	investor-owned corp.	92.9	27%	22%	1.0%	47%	1%	2%
13	PPL	investor-owned corp.	86.6	64%	14%	0.2%	20%	1%	0%
14	US Corps of Engineers	federal power authority	73.3	0%	0%	0.0%	0%	100%	0%
15	Xcel	investor-owned corp.	73.2	60%	19%	0.0%	17%	2%	2%
16	Energy Future Holdings	privately held corp.	68.4	71%	1%	0.1%	27%	0%	0%
17	Dynegy	investor-owned corp.	58.7	73%	27%	0.1%	0%	0%	0%
18	PSEG	investor-owned corp.	54.1	12%	32%	2.0%	54%	0%	0%
19	Ameren	investor-owned corp.	43.6	76%	0%	0.1%	21%	3%	0%
20	DTE Energy	investor-owned corp.	42.8	72%	3%	0.2%	18%	0%	7%
21	US Bureau of Reclamation	federal power authority	42.1	10%	0%	0.0%	0%	90%	0%
22	AES	investor-owned corp.	37.6	85%	7%	0.2%	0%	0%	7%
23	GDF Suez	foreign-owned corp.	32.7	17%	78%	0.7%	0%	2%	3%
24	San Antonio City	municipality	29.2	51%	21%	0.0%	28%	0%	0%
25	PG&E	investor-owned corp.	29.0	0%	21%	0.0%	59%	19%	1%
26	Energy Capital Partners	privately held corp.	28.6	32%	57%	0.3%	0%	0%	10%
27	Salt River Project	power district	27.9	55%	24%	0.1%	20%	0%	0%
28	Pinnacle West	investor-owned corp.	27.6	44%	21%	0.0%	34%	0%	1%
29	New York Power Authority	state power authority	25.7	0%	18%	0.8%	0%	81%	0%
30	Westar	investor-owned corp.	25.3	77%	5%	0.1%	16%	0%	2%
31	General Electric	investor-owned corp.	25.2	47%	48%	0.5%	0%	0%	4%
32	Great Plains Energy	investor-owned corp.	24.9	80%	1%	0.2%	16%	0%	2%
33	Wisconsin Energy	investor-owned corp.	24.1	81%	13%	0.1%	0%	2%	4%
34	SCANA	investor-owned corp.	23.4	51%	26%	0.4%	20%	1%	1%
35	Santee Cooper	state power authority	23.1	72%	17%	0.2%	10%	1%	1%
36	OGE	investor-owned corp.	22.8	61%	32%	0.0%	0%	0%	7%
37	Oglethorpe	cooperative	22.3	32%	24%	0.0%	44%	0%	0%
38	CMS Energy	investor-owned corp.	21.8	73%	17%	0.2%	0%	2%	8%
39	EDF	foreign-owned corp.	21.7	0%	0%	0.0%	75%	0%	25%
40	LS Power	privately held corp.	19.8	31%	64%	0.2%	0%	0%	4%
41	TECO	investor-owned corp.	18.7	62%	38%	0.1%	0%	0%	0%
42	Alliant Energy	investor-owned corp.	18.6	73%	16%	0.2%	0%	2%	9%
43	Basin Electric Power Coop	cooperative	18.4	90%	4%	0.1%	0%	0%	6%
44	ArcLight Capital	privately held corp.	16.8	50%	35%	0.0%	0%	0%	14%
45	NE Public Power District	power district	16.5	61%	1%	0.0%	36%	0%	1%
46	Omaha Public Power District	power district	16.2	73%	1%	0.1%	26%	0%	0%
47	Iberdrola	foreign-owned corp.	15.9	0%	5%	0.0%	0%	2%	93%
48	NC Public Power	municipality	15.5	6%	0%	0.0%	94%	0%	0%
49	Associated Electric Coop	cooperative	15.0	81%	19%	0.1%	0%	0%	0%
50	NiSource	investor-owned corp.	14.9	83%	17%	0.0%	0%	0%	0%
51	Tenaska	privately held corp.	14.6	0%	97%	0.9%	0%	0%	2%
52	JEA	municipality	14.2	61%	29%	0.1%	0%	0%	10%

* Breakdown of ownership categories provided in endnote 2 privately/investor owned public power cooperative

Rank	Owner	Ownership Type*	Total (million MWh)	Coal	Natural Gas	Oil	Nuclear	Hydro	Renewable/ Other
53	IDACORP	investor-owned corp.	13.8	46%	9%	0.1%	0%	45%	0%
54	Rockland Capital	privately held corp.	13.6	2%	96%	0.1%	0%	0%	2%
55	Los Angeles City	municipality	13.5	27%	54%	0.0%	14%	2%	3%
56	Edison International	investor-owned corp.	13.3	0%	47%	0.2%	38%	12%	2%
57	Tri-State	cooperative	12.8	95%	5%	0.1%	0%	0%	0%
58	Occidental	investor-owned corp.	12.5	0%	99%	0.0%	0%	0%	1%
59	Intermountain Power Agency	power district	12.4	100%	0%	0.1%	0%	0%	0%
60	Riverstone	privately held corp.	12.1	53%	45%	1.5%	0%	0%	0%
61	Dow Chemical	investor-owned corp.	12.0	0%	93%	0.0%	0%	0%	7%
62	Municipal Elec. Auth. of GA	municipality	11.9	30%	14%	0.0%	56%	0%	0%
63	Puget Holdings	privately held corp.	11.6	39%	36%	0.1%	0%	9%	17%
64	Portland General Electric	investor-owned corp.	11.1	43%	31%	0.1%	0%	16%	10%
65	Exxon Mobil	investor-owned corp.	11.1	0%	90%	0.0%	0%	0%	10%
66	Arkansas Electric Coop	cooperative	11.0	90%	4%	0.1%	0%	6%	0%
67	Energy Investors Funds	privately held corp.	10.8	16%	82%	0.2%	0%	1%	1%
68	PNM Resources	investor-owned corp.	10.8	55%	13%	0.3%	31%	0%	1%
69	Invenergy	privately held corp.	10.8	0%	19%	0.0%	0%	0%	81%
70	Seminole Electric Coop	cooperative	10.7	76%	23%	0.2%	0%	0%	0%
71	EDP	foreign-owned corp.	10.6	0%	0%	0.0%	0%	0%	100%
72	Great River Energy	cooperative	10.5	97%	2%	0.2%	0%	0%	1%
73	Lower CO River Authority	state power authority	10.3	64%	35%	0.1%	0%	0%	0%
74	Sempra	investor-owned corp.	10.2	0%	75%	0.0%	0%	0%	25%
75	East Kentucky Power Coop	cooperative	10.2	94%	5%	0.2%	0%	0%	1%
76	BP	foreign-owned corp.	10.0	0%	50%	0.0%	0%	0%	49%
77	Energy Northwest	municipality	9.9	0%	0%	0.0%	96%	1%	2%
78	CLECO	investor-owned corp.	9.9	24%	43%	0.0%	0%	0%	33%
79	Integrys	investor-owned corp.	9.7	74%	18%	0.1%	0%	4%	4%
80	Brookfield	foreign-owned corp.	9.6	0%	1%	0.0%	0%	87%	12%
81	ALLETE	investor-owned corp.	9.5	85%	0%	0.0%	0%	3%	12%
82	El Paso Electric	investor-owned corp.	9.5	6%	40%	0.0%	54%	0%	0%
83	PUD No 1 of Chelan County	power district	9.5	0%	0%	0.0%	0%	100%	0%
84	Buckeye Power	cooperative	9.4	99%	1%	0.3%	0%	0%	0%
85	Fortis Inc.	foreign-owned corp.	8.8	83%	15%	0.1%	0%	0%	1%
86	Entegra Power	privately held corp.	8.8	0%	100%	0.0%	0%	0%	0%
87	E.ON	foreign-owned corp.	8.8	0%	0%	0.0%	0%	0%	100%
88	Brazos Electric Power Coop	cooperative	8.8	18%	81%	0.1%	0%	0%	0%
89	PUD No 2 of Grant County	power district	8.4	0%	0%	0.0%	0%	100%	0%
90	Austin Energy	municipality	8.3	41%	19%	0.0%	40%	0%	0%
91	The Carlyle Group	privately held corp.	7.9	11%	86%	0.1%	0%	0%	3%
92	TransCanada	foreign-owned corp.	7.9	0%	75%	2.4%	0%	18%	4%
93	Big Rivers Electric	cooperative	7.7	86%	0%	0.2%	0%	0%	13%
94	Avista	investor-owned corp.	7.3	19%	21%	0.0%	0%	56%	4%
95	Hoosier Energy	cooperative	7.3	97%	2%	0.1%	0%	0%	0%
96	TransAlta	foreign-owned corp.	7.2	93%	1%	0.1%	0%	0%	6%
97	Seattle City Light	municipality	7.1	0%	0%	0.0%	0%	100%	0%
98	International Paper	investor-owned corp.	6.9	4%	16%	1.5%	0%	0%	78%
99	NorthWestern Energy	investor-owned corp.	6.9	39%	6%	0.2%	0%	53%	2%
100	Sacramento Municipal Util Dist	municipality	6.8	0%	81%	0.0%	0%	11%	8%
		Total (top-100 producers)	3,447.8	40%	26%	0.1%	22%	7%	5%
		Total (all U.S. producers)	4,056.8	39%	28%	0.3%	19%	7%	7%

* Breakdown of ownership categories provided in endnote 2 privately/investor owned public power cooperative

Endnotes

1. Private entities include investor-owned and privately held utilities and non-utility power producers (e.g., independent power producers). Cooperative electric utilities are owned by their members (i.e., the consumers they serve). Publicly-owned electric utilities are nonprofit government entities that are organized at either the local or State level. There are also several Federal electric utilities in the United States, such as the Tennessee Valley Authority

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5. Retail electricity prices are based on the overall cost of procuring electricity over a certain period. Consequently, wholesale prices reaching zero during certain hours may or may not have an impact on retail electricity prices charged to ratepayers. See also Gross, Daniel. "The Night They Drove the Price of Electricity Down." Slate, September 18, 2015, Accessed April 12, 2016, http://www.slate.com/articles/business/the_juice/2015/09/texas_electricity_goes_negative_wind_power_was_so_plentiful_one_night_that.html.

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13. Includes federal appliance standards, utility implemented energy efficiency programs, performance contracting, building codes, etc.
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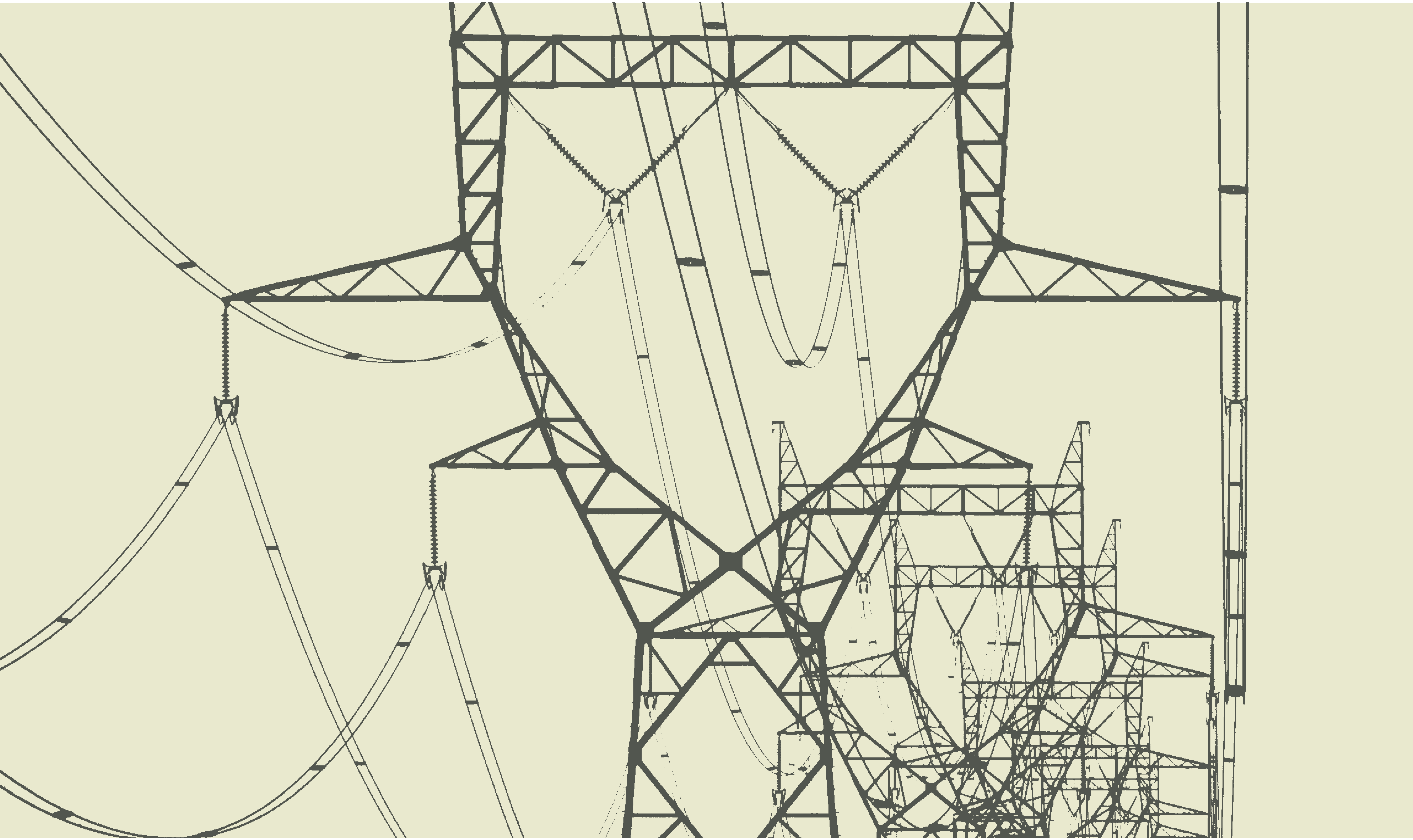

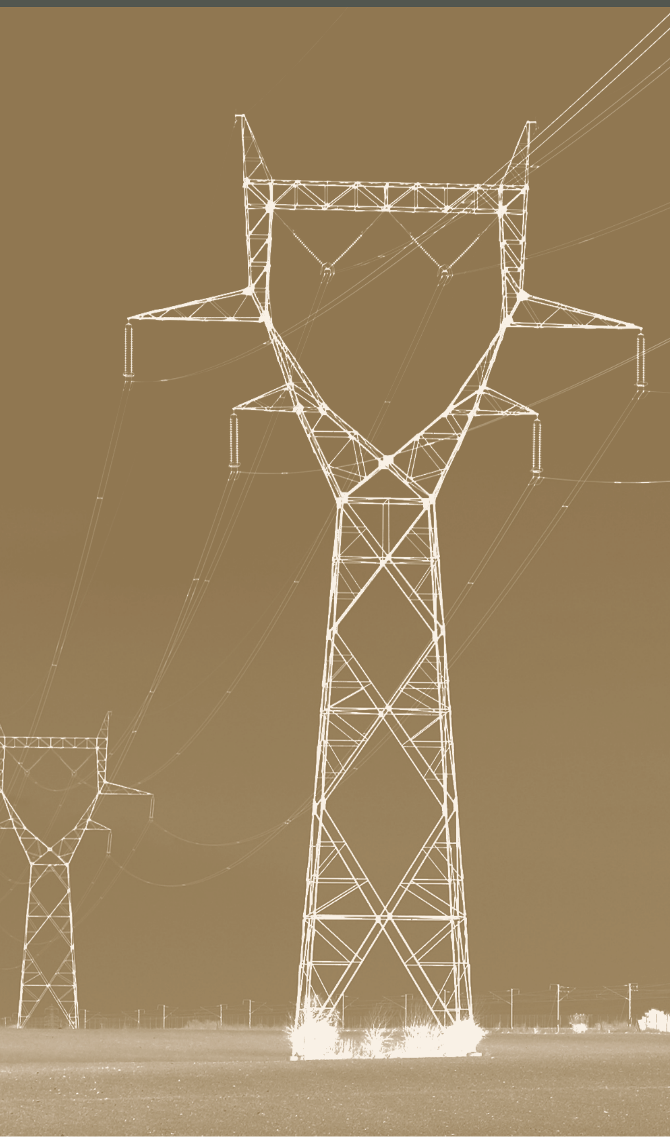

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