IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

State of West Virginia, et al.	)	
	)	
Petitioners,	)	
	)	
v.	)	Case No. 15-1363 (and
	)	consolidated cases)
United States Environmental Protection	)	
Agency, et al.	)	
	)	
Respondents.	)	

DECLARATION OF DAVID SCHLISSEL

INSTITUTE FOR ENERGY ECONOMICS AND FINANCIAL ANALYSIS

Introduction and Qualifications

I, David Schlissel, declare:

1. I am Director of Resource Planning Analysis for the Institute for Energy Economics and Financial Analysis ("IEEFA").[1] I conduct research on a range of fossil fuel and renewable resource issues including coal-fired electric generating unit ("EGU") costs and operating performance and the relative costs of natural gas and renewable alternatives.

2. Prior to joining IEEFA, I worked for four decades as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. My clients included state regulatory commissions, state attorneys general, several states, state consumer advocates, cities, power plant suppliers, an independent power producer, and consumer and environmental organizations. I have researched coal, energy, and environmental issues in more than 30 states and several foreign nations and have published numerous reports on the factors that have influenced the economic and financial viability of proposed and existing fossil fuel-fired power plants and renewable alternatives. I also have testified as an expert witness in more than 165 proceedings before 35 state public utility commissions, before the Federal Energy Regulatory Commission ("FERC") and the U.S. Nuclear Regulatory Commission, and in state and federal court litigation.

[1] My bio is included as an attachment to this declaration.

3. I hold undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

4. This declaration is based on my education, experience, and review of materials I gathered, in addition to those submitted by petitioners or provided to me by counsel.

Summary of Opinions

5. Due to a number of circumstances completely independent of the Clean Power Plan, many thousands of megawatts ("MW") of existing coal-fired EGUs in the U.S. have come under substantial economic and financial stress and have either retired, are scheduled to retire, or are at risk of retirement in the coming years. These circumstances include:

a. The collapse of natural gas prices in late 2008/early 2009 due to the large and growing supply of shale gas and a subsequent decline in the cost of generating power at natural gas-fired power plants;

b. Increased competition from renewable wind and solar resources, as the total MW of installed wind and solar capacity have soared in recent years due to steep declines in the installation prices for wind and solar photovoltaic ("PV") resources and support from federal and state programs;

c. Steep declines in the amount of power generated at many existing coal-fired EGUs as that generation has been displaced by less-expensive power from natural gas-fired EGUs and, in recent years, power from renewable wind and solar resources;

d. Precipitous declines in energy market prices in the deregulated wholesale markets where many existing coal plants are located;

e. An aging coal fleet that can be expected to have higher operating and maintenance costs, continuing annual capital expenditures, and degrading operating performance as it ages;.

f. Rising coal plant operating and maintenance costs, including the need for additional capital expenditures ("capex") to replace existing equipment and components that have degraded due to age or service related wear-and-tear and for upgrades required to address environmental regulations other than the Clean Power Plan; and

g. Flat or relatively flat growth in electric usage driven by the Great Recession of 2008-09 and the increased deployment of energy efficiency and distributed, on-site renewable resources.

6. All of these circumstances are independent of the Clean Power Plan and all have combined to undercut the viability of continued operation of existing coal-fired plants and the profitability of the companies that own them. As natural gas prices have fallen, regional power market prices have declined precipitously and coal plant generation has dropped steeply. Consequently, revenues from coal-fired EGUs have decreased, investments in environmental plant upgrades have been called into question, and coal has lost a significant market share to natural gas and renewable resources.

7. As a result of these market forces and economic trends, a substantial amount of coal capacity was retired, announced for retirement, or targeted for conversion to gas between 2009 and March 2014 —before the Clean Power Plan was even proposed, let alone finalized. At that time, analysts anticipated that actual future retirements of coal-fired EGU capacity would exceed the retired and announced retirements that had occurred to date.

8. In my opinion, additional retirements of coal-fired EGUs can be expected in coming years, independent of the Clean Power Plan, as none of the market forces and trends listed above and discussed in this declaration can reasonably be expected to abate sufficiently, if at all, to support the continued operation of many existing coal-fired EGUs, including those listed in Exhibits 29 and 31 of the Declaration and Report of Seth Schwartz submitted in support of the National Mining Association's stay motion.

9. Furthermore, staying the Clean Power Plan will not make these coal-fired assets any more viable in either the near-term or the long-term. Even if the Court were to stay the rule during the pendency of this litigation, it would not guarantee—or even make it less likely—that power plants would not have to pay a price for their carbon pollution in 2022, either under the Clean Power Plan or other carbon regulations that may be enacted at the state or federal levels. In fact, a stay would inject *more* regulatory uncertainty into the process and thereby disrupt utilities' decision-making processes (*see* Sanzillo Decl. ¶¶ 42–45). For example, if an owner were to make a major capital investment at an aging plant on the basis of a stay, it

might find that investment to have been wasted two years down the road if the court ultimately upheld the rule, whereas the economically wiser choice would have been to await the final outcome of litigation before making the investment. There is therefore no basis to assert that staying the Clean Power Plan will facilitate plant owners' decision-making during the litigation period.

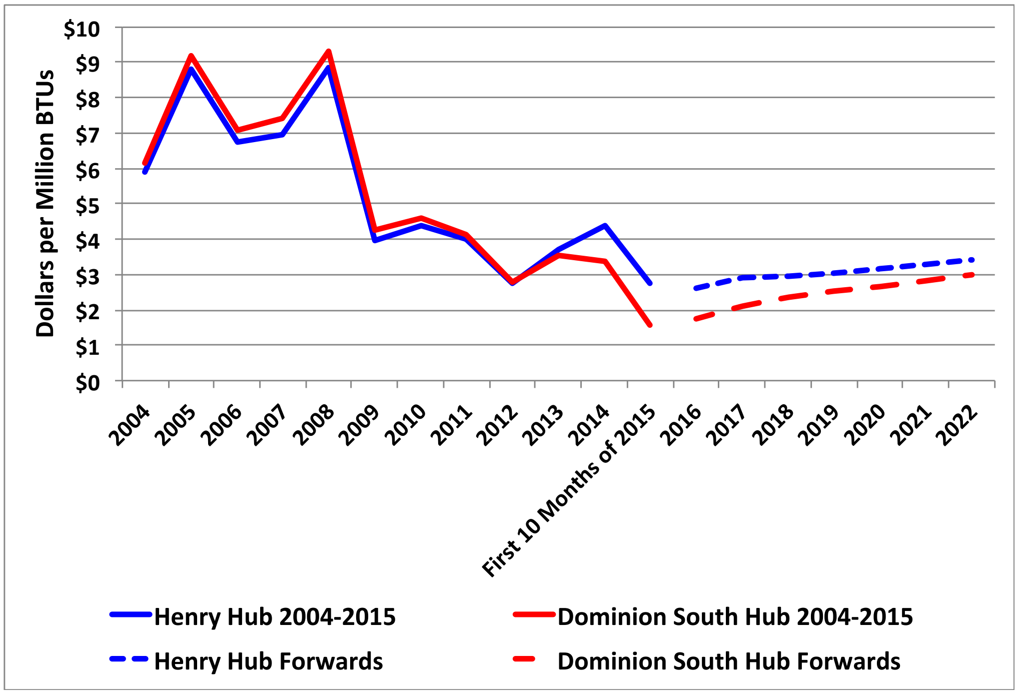
Opinions

A. Natural Gas Prices Have Declined Precipitously Beginning in Late 2008 and Early 2009.

10. The Henry Hub in Louisiana has traditionally been the most important pricing location for natural gas in the United States. However, in recent years, the Dominion South Hub in Southwest Pennsylvania has gained in importance due to the discovery and production of increasing amounts of natural gas from the Marcellus Shale in the Eastern United States.

11. Figure 1 below shows the historical annual prices for natural gas at the Henry Hub and Dominion South Hubs between the years of 2004 and the first ten months of 2015, as well as the forwards prices for the years 2016 through 2022. The sharp decline between gas prices in 2008 and 2009 is readily apparent.

Fig. 1: Natural Gas Prices at Henry Hub and Dominion South Hub[2]



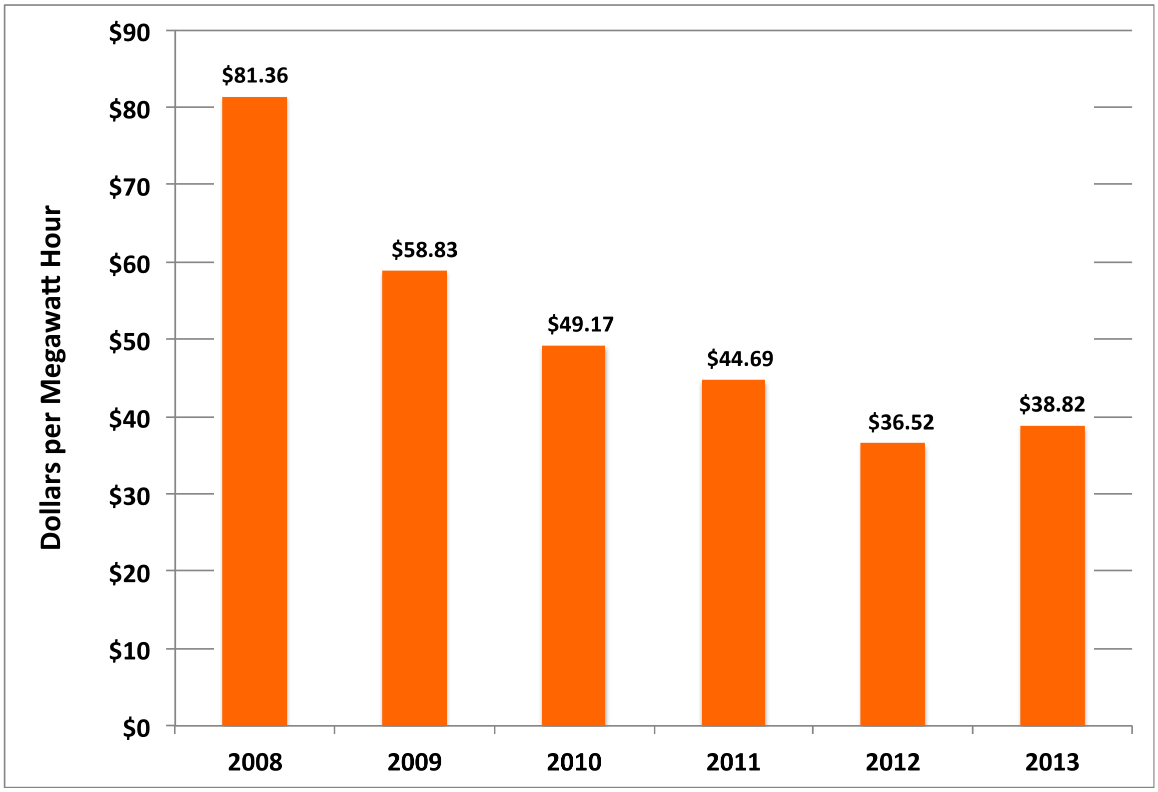
12. Although, as shown in Figure 1 above, gas prices rebounded somewhat in 2014, largely due to the Polar Vortex event in the first months of the year, they again declined quite significantly during 2015. As a result, gas prices have fallen at Henry Hub by 69 percent between 2008 and 2015 and at Dominion South Hub by 83 percent.[3]

13. This steep drop in natural gas prices has led to significant declines in the operating costs at gas-fired power plants, which has made them much more competitive against generation at coal-fired units. As an illustration of this, Figure 2 below shows the over 50 percent decline in the average cost of

[2] Data on historical natural gas prices derived from SNL Financial. Forward prices from OTC Global Holdings as of November 12, 2015, downloaded from SNL Financial.
[3] *Id.*

generating power at gas-fired combined cycle EGUs in Florida between the years 2008 and 2013.

<u>Fig. 2: Average Cost of Generating Power at Natural Gas-Fired Combined Cycle Power Plants in Florida</u>[4]



14. Most importantly, natural gas prices are not expected to rebound significantly at any time in the foreseeable future, as evidenced in the natural gas forwards prices shown in Figure 1 above. These forwards prices represent the prices at which gas can be purchased today for delivery months or years in the future. As such, they represent the market's outlook for future natural gas prices. At both Henry Hub and Dominion South Hub, gas

[4] Data derived from plant operating cost information published by SNL Financial.

forwards through 2022 sell at or below typical gas prices that the market has seen since the initial price plummet in 2008-09.

15. In addition to Henry Hub and Dominion South Hub, there are a number of other hubs (i.e., pricing locations) around the U.S. at which natural gas is sold and purchased. These hubs have experienced the same steep decline in energy market prices since 2008-09 and similarly expect that gas prices will remain low in the coming years. Fuel industry and financial community analysts also forecast very slow growth in natural gas prices over the next decade or so. For example, a Wood Mackenzie analyst has projected that the potential supply of natural gas and the ability of producers to turn profits at lower prices are likely to keep natural gas below $4 per million cubic foot for the foreseeable future.[5]

16. As a result, the prices of generating power at natural gas-fired EGUs are not expected to increase significantly in coming years. This development will maintain, and perhaps even enhance, natural gas's competitive advantage over coal for generating electricity. And it is entirely independent of the Clean Power Plan.

B. Coal-Fired EGUs Face Increased Competition from Renewable Wind and Solar Resources.

17. At the same time that natural gas prices have declined precipitously, there also has been a tremendous increase in the solar and wind capacity on

[5] 'Tough to get beyond $4': Wood Mackenzie analyst sees little gas-price upside, SNL Financial (May 20, 2015).

the electric grid, due in large part to steep declines in installation costs, as I will discuss below. The adoption of renewable portfolio standards ("RPS") in nearly 30 states, which typically require utilities to purchase a portion of their power from renewable resources, also has contributed to the increase in solar and wind capacity.

18. For example, as shown in Figures 3 and 4 below, as of the end of 2014, the U.S. had more than 69 GW of installed wind capacity and more than 18 GW of installed solar PV capacity. These numbers represent an addition of 54.6 GW of new wind capacity and 16.9 GW of new solar capacity just between 2007 and 2014. Together, wind and solar represented almost 43 percent of the nation's total generation capacity additions during this period.[6]

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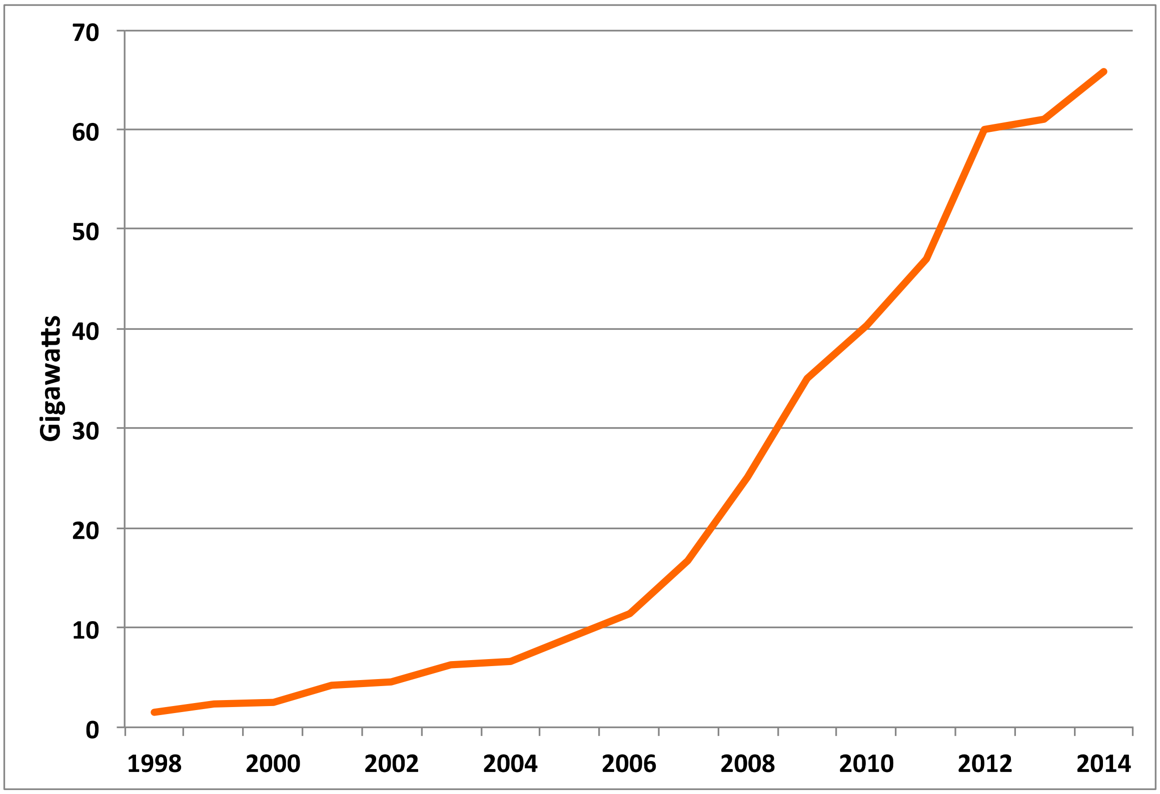
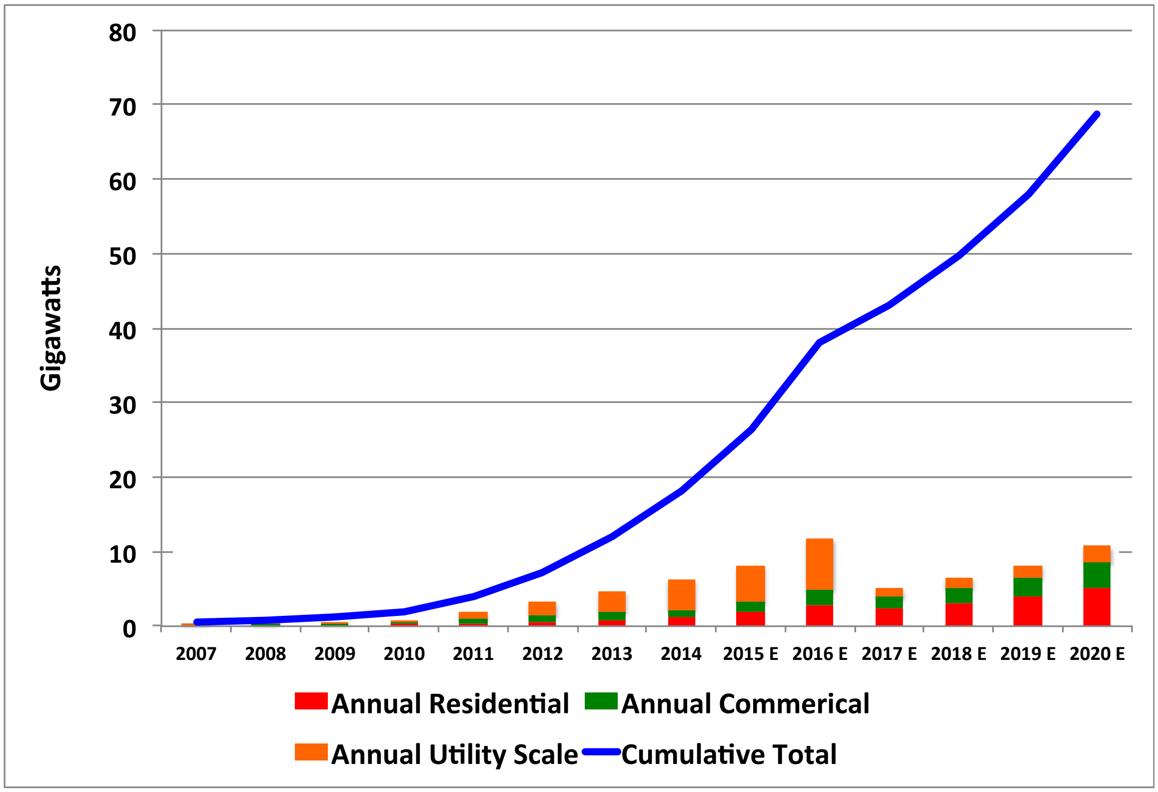
[6] Ryan Wiser, et al., U.S. Dep't of Energy, *2014 Wind Technologies Market Report* (Aug. 2015), at Fig. 2, *available at* http://www.energy.gov/sites/prod/files/2015/08/f25/2014-Wind-Technologies-Market-Report-8.7.pdf.

Fig. 3: Domestic U.S. Wind Capacity[7]



[7] *Id.* at Fig. 1.

Fig. 4: U.S. Installed Solar Photovoltaic Capacity[8]



19. Renewables resources' share of the market is likely to increase significantly in coming years, as another 50 GW of solar PV capacity are expected to be added by 2020[9] and more than 13 GW of new wind capacity are already under construction.[10] This will increase the economic and financial stress on coal plant owners even without the Clean Power Plan.

20. The energy generated by renewable resources (other than hydropower) more than doubled between 2007 and 2014, increasing from

[8] Mark Bolinger and Joachim Seel, Lawrence Berkeley Nat'l Laboratory, Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States (Sept. 2015), at Fig. 1, available at https://emp.lbl.gov/publications/utility-scale-solar-2014.
[9] *Id.*
[10] American Wind Energy Ass'n, *U.S. Wind Industry Third Quarter 2015 Market Report, Executive Summary* (Oct. 22, 2015), at 9, *available at* http://www.awea.org/3q2015.

2.5 percent of the total U.S. electric generation to 6.8 percent.[11] Wind resources alone provided 11 percent of the energy in the ERCOT market in Texas in 2014,[12] as well as 8 percent of the energy in the MISO market in 2013 and 6 percent in 2014.[13]

21. This rapid growth in new wind and solar capacity and generation has been due to several factors, including declining installation rates, improved operational efficiencies, increased interest in carbon-free resources, and the adoption of renewable portfolio or renewable energy standards by a number of states.

22. For example, wind turbine prices have declined substantially in recent years despite increases in hub heights and larger rotor diameters.[14] All of the changes discussed above have combined with improved turbine technology to reduce project costs and wind power purchase agreements ("PPA") prices.[15] As a result, the prices for power from wind PPAs have dropped to all-time lows, declining from $70 per megawatt-hour ("MWh") for PPAs executed in 2009 to a nationwide average of around $23.50 per MWh for PPAs signed in 2014.[16] Despite uncertainty about the future of the federal

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[11] EIA, *Short-Term Energy Outlook* (Nov. 2015), Fig. 25, *available at* http://www.eia.gov/forecasts/steo/xls/Fig25.xlsx.

[12] ERCOT, *2014 State of the Market Report* (July 2015), at xiv, *available at* https://www.potomaceconomics.com/uploads/ercot_documents/2014_ERCOT_State_of_the_Market_Report.pdf.

[13] MISO, *2014 State of the Market Report* (June 2015) at 5, *available at* https://www.misoenergy.org/Library/Repository/Report/IMM/2014%20State%20of%20the%20Market%20Report.pdf.

[14] Wiser, *supra* n. 6, at 29–31, 46–54.

[15] *Id.* at 56–60.

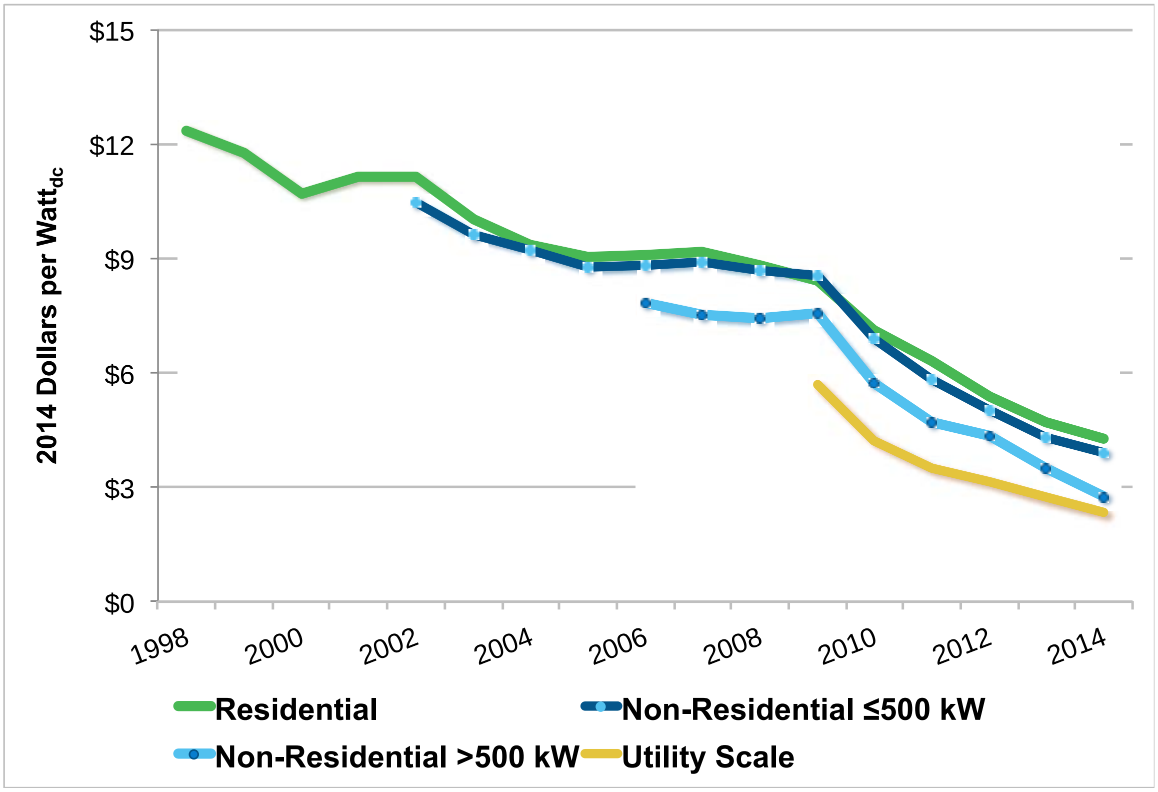
[16] *Id.* at 56.

wind Production Tax Credit, further decreases in wind prices can be expected in coming years that will put further pressure on coal generation.[17]

23. Installation prices for utility-scale solar projects and for distributed residential and commercial solar PV have also plummeted in recent years. As shown in Figure 5 below, distributed solar PV installation prices decreased by an average of 6 to 8 percent per year from 1998 through 2013, dropping an additional 9 percent from 2013 to 2014. Preliminary data suggest similar price declines in the first half of 2015. Median utility-scale solar PV installation prices have fallen by more than 50 percent between 2007-2009 and 2014.

[17] Christopher Martin and Justin Doom, *Wind Power Without U.S. Subsidy to Become Cheaper Than Gas*, Bloomberg Business (Mar. 12, 2015), *available* at http://www.bloomberg.com/news/articles/2015-03-12/wind-energy-without-subsidy-will-be-cheaper-than-gas-in-a-decade; *see also* U.S. Dep't of Energy, *WindVision: A New Era for Wind Power in the United States (Executive Summary)* (Mar. 2015), *available at* http://energy.gov/sites/prod/files/wv_executive_summary_overview_and_key_chapter_findings_final.pdf.

Fig. 5: Solar PV Installation Prices (Median Values) [18]



24. Solar installation prices are expected to continue to decline in coming years, with some analysts projecting prices as low as $1.50 to $3 per watt by 2016, with additional declines expected in later years.[19] By comparison, median prices as recently as 2009 averaged around $7.50 to $9 per watt, as seen in Figure 5 above.

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[18] Galen L. Barbose, et al., Lawrence Berkeley Nat'l Laboratory, Tracking the Sun VIII: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2014 (Aug. 2015), at Fig. 7, available at https://emp.lbl.gov/publications/tracking-sun-viii-install.

[19] David Feldman, et al., Nat'l Renewable Energy Laboratory and the Lawrence Berkeley Nat'l Laboratory, *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections, 2014 Edition* (Sept. 22, 2014), at slides 5 and 26-28, *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf.

25. The prices for long-term PPAs from utility-scale solar PV projects have fallen so dramatically since 2009 that the median PPA price in the U.S. is now just below $50 per MWh, down from prices above $100 per MWh for PPAs signed as recently as 2010.[20]

26. These recent declines in wind and solar PPA prices, the underlying declines in wind and solar installation prices, and the competitive advantage they give renewable resources over coal-fired EGUs are completely independent of the Clean Power Plan.

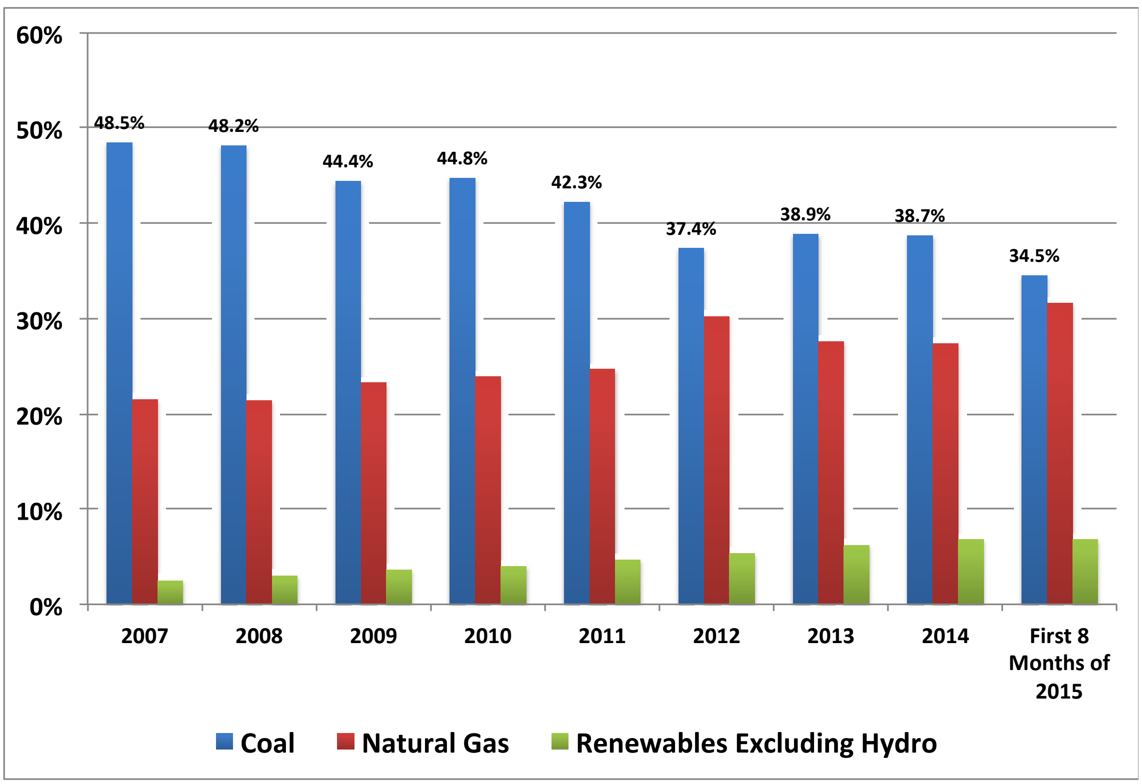
C. Generation at Coal-Fired EGUs Has Declined Steeply As a Result of Low Natural Gas Prices and the Addition of More Renewable Wind and Solar Capacity.

27. In recent years, low natural gas prices have allowed natural gas-fired EGUs to reduce their operating costs and to displace coal as the marginal fuel for many hours of the year in wholesale energy markets nationwide. The substantial drop in natural gas prices beginning in late 2008 and early 2009, reinforced more recently by a surge of new renewable resources, has driven down the amount of power generated from coal in the U.S. quite significantly. This trend is readily apparent in coal-fired EGU generation data over the past several years at national, regional, company-wide, and individual plant levels.

[20] Bolinger, *supra* n. 8, at 33, 35, and 37.

28. As shown in Figure 6 below, coal-fired generation dropped from 48.5 percent of total U.S. electric generation in 2007 to 38.7 percent in 2014 and to only 34.5 percent in the first eight months of 2015. [21] At the same time that coal usage has been declining, the percentages of total U.S. electric generation from natural gas and non-hydro renewable resources have been increasing significantly.

Fig. 6: Total U.S. Electric Generation from Coal, Natural Gas and Non-Hydro Renewable), 2007 Through the First Eight Months of 2015[22]



[21] Derived from EIA, *Electric Power Monthly* (Feb. 2015 and Aug. 2015), workpaper for Table 1_01, *available at* http://www.eia.gov/electricity/monthly/index.cfm.
[22] *Id.*

29. As the trends shown in Figure 6 suggest, generation from coal in the regional markets operated by independent system operators has also declined significantly since 2007. For example, coal represented 55 percent of the fuel mix in PJM in 2007.[23] However, by 2014, coal generation was only 43.5 percent of the fuel mix,[24] declining to just 38.5 percent in the first three quarters of 2015.[25] Compared to the first nine months of 2014, coal generation decreased 13.6 percent during the first three quarters of 2015.[26]

30. The generation from individual company coal-fleets also declined precipitously as a result of the increasing competition from natural gas, as illustrated in Figure 7 below.

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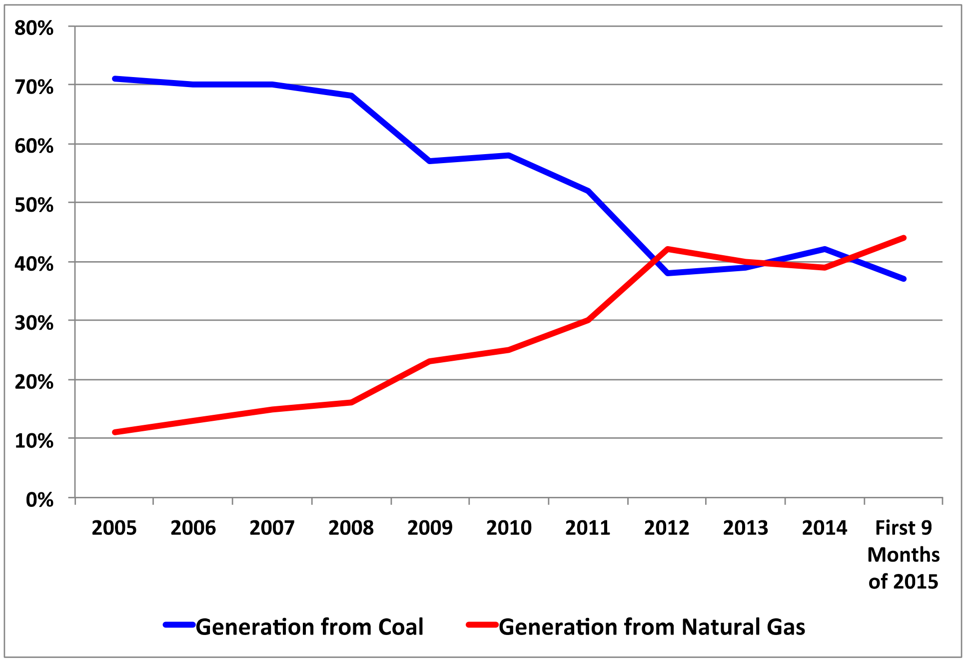
[23] PJM, *2007 State of the Market Report*, Vol. II (Mar. 11, 2008), at 110, *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2007.shtml.

[24] PJM, *2014 State of the Market Report*, Vol. II (Mar. 12, 2015), at 16, *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2014/2014-som-pjm-volume2.pdf.

[25] PJM, *2015 Quarterly State of the Market Report, January – September* (Nov. 12, 2015), at 70, *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015/2015q3-som-pjm.pdf.

[26] *Id.*

Fig. 7: Southern Company Generation from Coal and Natural Gas, 2005-2015[27]

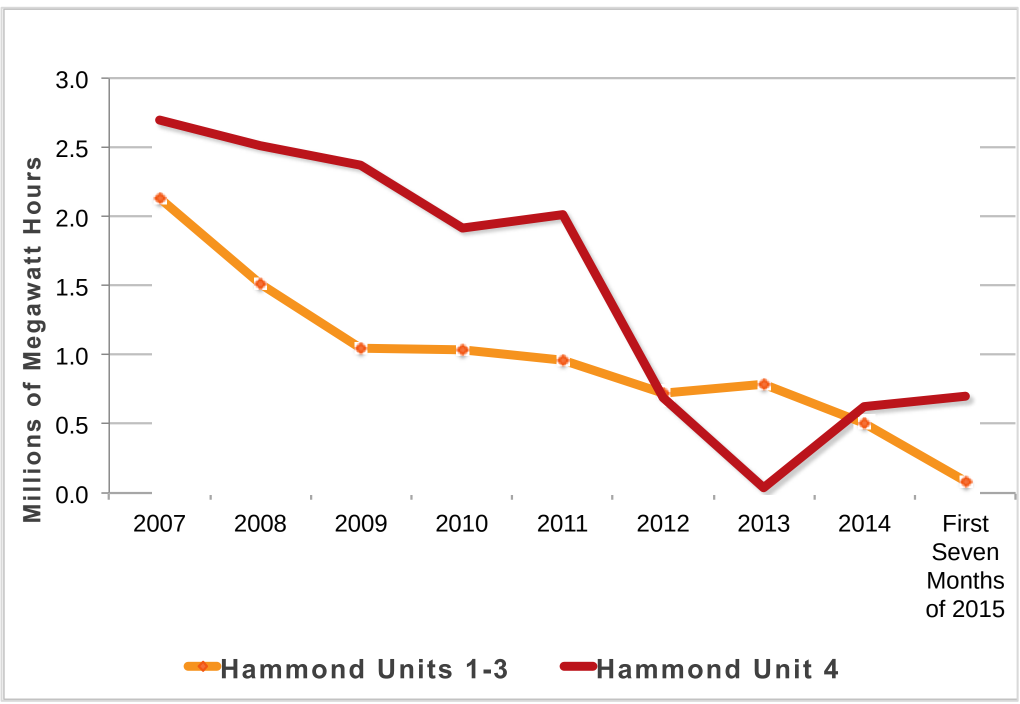


31. Southern Company's generation from coal declined from 70 percent of its total generation in 2007 (before natural gas prices began to decline in late 2008/early 2009) to 37 percent in the first three quarters of 2015. At the same time, as shown in Figure 7, Southern Company's generation from natural gas tripled from 15 percent in 2007 to 44 percent in the first three quarters of 2015.

[27] Data derived from Southern Company Form 10-K SEC Filings for the years 2005-2014 and Form 10-Q Filing for the third quarter of 2015.

32. The heightened competition from natural gas, and more recently, renewable resources, has meant that many coal-fired EGUs that previously operated as baseload units—meaning that they were operated to generate power as much around the clock as possible—have been reduced to being dispatched as monthly or seasonal peaking units, or have not been operated at all. Georgia Power Company's four coal-fired units at Plant Hammond provide a vivid example of how low natural gas prices have affected the generation at previously baseload-operated coal-fired EGUs.

<u>Fig. 8: Annual Generation at Plant Hammond Units 1-4, 2005-July 2015</u>[28]



33. Such intermittent operation compromises coal plant efficiency and, as a result, economic viability—and is completely independent of the Clean

[28] Data derived from Hammond's EIA Form 923, as reported by SNL Financial.

Power Plan. Intermittent operation, with frequent start-ups and power-downs, puts stress on plant components, raises their variable operating costs, and causes more frequent outages.[29] As a result, plant operators often find it more profitable to retire aging coal plants rather than operate them as intermittent units for extended periods of time.

34. As shown in Figure 8 above, even the amount of power generated by the largest and newest EGU at Plant Hammond—Unit 4—has declined significantly since 2008, except for a slight uptick in early 2014 due to the Polar Vortex Event.

35. A closer look at month-by-month generation over the past three years shows that Units 1-3 at Plant Hammond have generated only very small amounts of power in any given month. Unit 4 has essentially become a seasonal "peaker," producing the greater portion of its output in the high-demand summer and winter months, with little-to-no generation the rest of the year.

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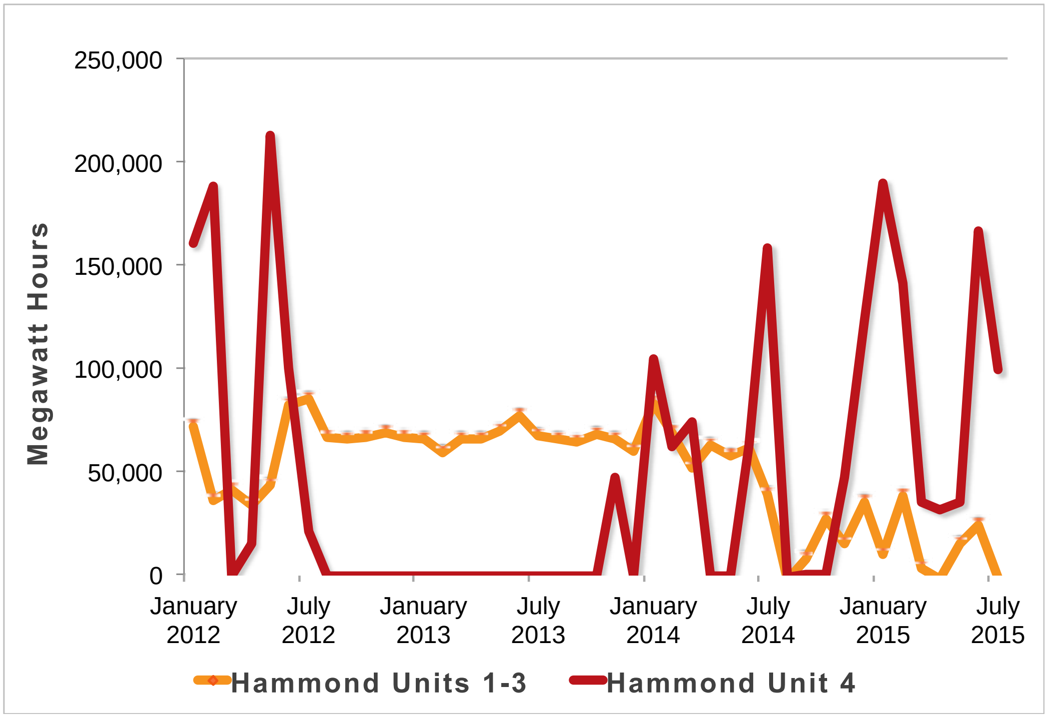
[29] Anya Litvak, *What happens when coal plants move from leaders to followers?*, Pittsburg Post-Gazette (Nov. 24, 2015), *available at* http://powersource.post-gazette.com/powersource/consumers-powersource/2015/11/24/What-happens-when-coal-plants-move-from-leaders-to-followers-baseload-cycling/stories/201511240007.

<u>Fig. 9: Monthly Generation at Plant Hammond Units 1-4, 2012 – July 2015[30]</u>



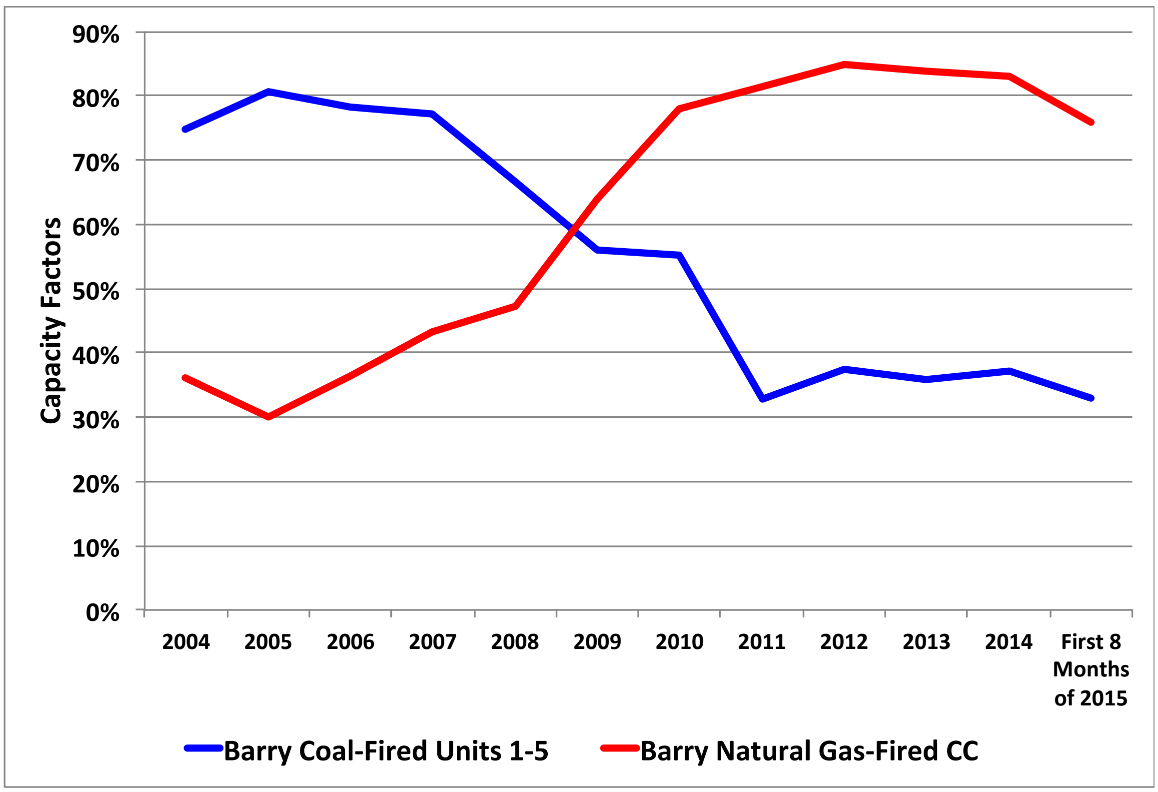
36. The industry metric "capacity factor" compares how much power an EGU actually generates in a specific time period, such as a month or a year, with how much power the plant would have produced if it had operated at its full capacity for all of the hours in the time period. A baseload EGU, like Plant Hammond used to be, typically operates at an average 60 to 80 percent capacity factor each year. However, Plant Hammond's operations have declined so substantially that the entire plant has averaged only a 16 percent capacity factor since the beginning of 2012.[31]

37. The impact that low natural gas prices have had on generation at coal-fired EGUs is, perhaps, most dramatically shown by those power plant sites

[30] *See supra* n. 28.
[31] *Id.*

that have both coal- and natural gas-fired EGUs. For instance, Figure 10 below shows how generation at the single combined cycle gas-fired unit at the Barry Electric Generating Station in Alabama has increased dramatically since 2008/2009, while at the same time, generation at Barry's five coal-fired units has declined substantially.

Fig. 10: Annual Generation at Barry Coal-Fired and Natural Gas-Fired Units, 2004 through the First Eight Months of 2015[32]



38. To summarize, the key points about this historic decline in coal-fired generation are that: (1) this trend is entirely independent of the Clean Power Plan; (2) the low gas prices and the increased development of less expensive renewable resources that led to coal's decline are likely to continue to

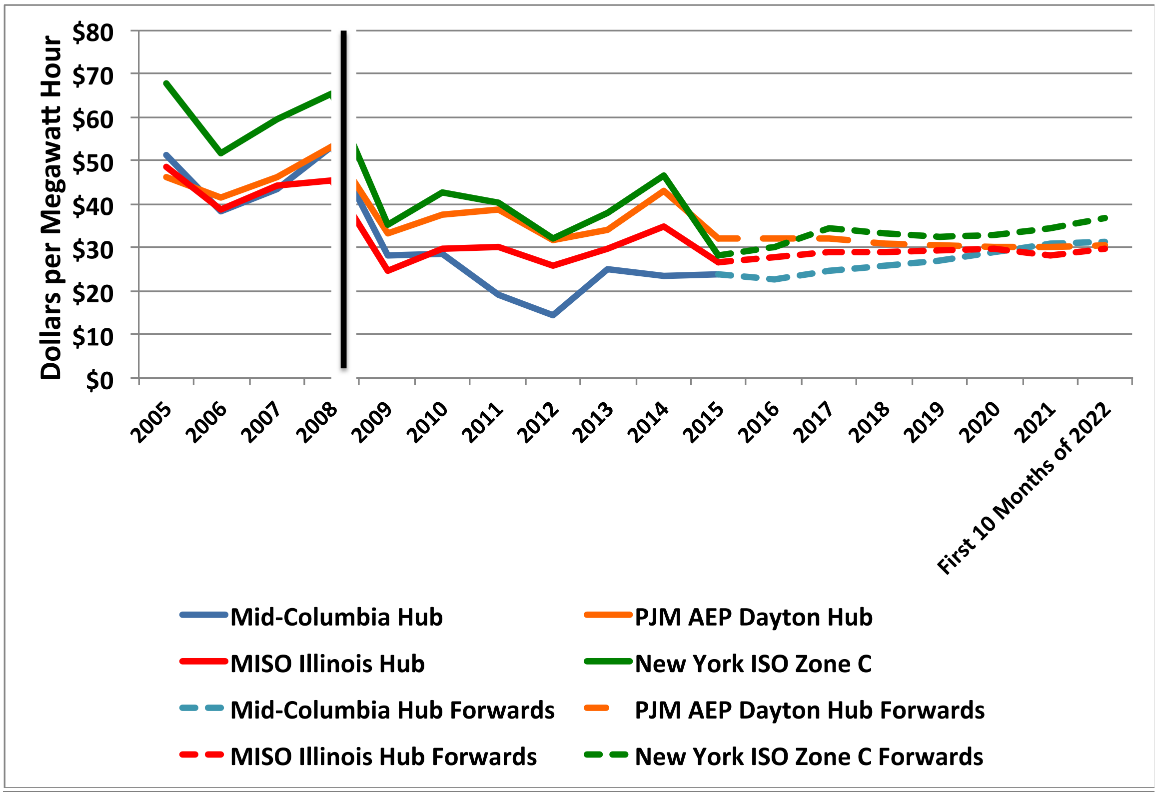
[32] Data derived from Hammond's EIA Form 923, as reported by SNL Financial.

undermine the viability of existing coal-fired EGUs for years, if not permanently; (3) as coal generation declines and units transition from baseload to intermittent operation, they become even less economic; and (4) these factors will lead to the retirement of more coal-fired EGUs in coming years, including many of the EGUs listed in Exhibits 29 and 31 of the Declaration and Report of Seth Schwartz.

D. The Collapse in Natural Gas Prices Has Led to a Steep Decline in Wholesale Electricity Prices.

39. At the same time that coal-fired electricity generation has declined substantially, wholesale electricity prices in markets around the nation also have declined as a result of low natural gas prices. This can be seen clearly in Figure 11 below, which depicts power prices in representative markets in the Northeast, the Midwest, and the Northwest.

Fig. 11: Energy Market Prices in Representative Wholesale Markets, 2005-2022[33]



40. The vertical line in Figure 11 represents the period in late 2008/early 2009 when natural gas prices began to decline precipitously.

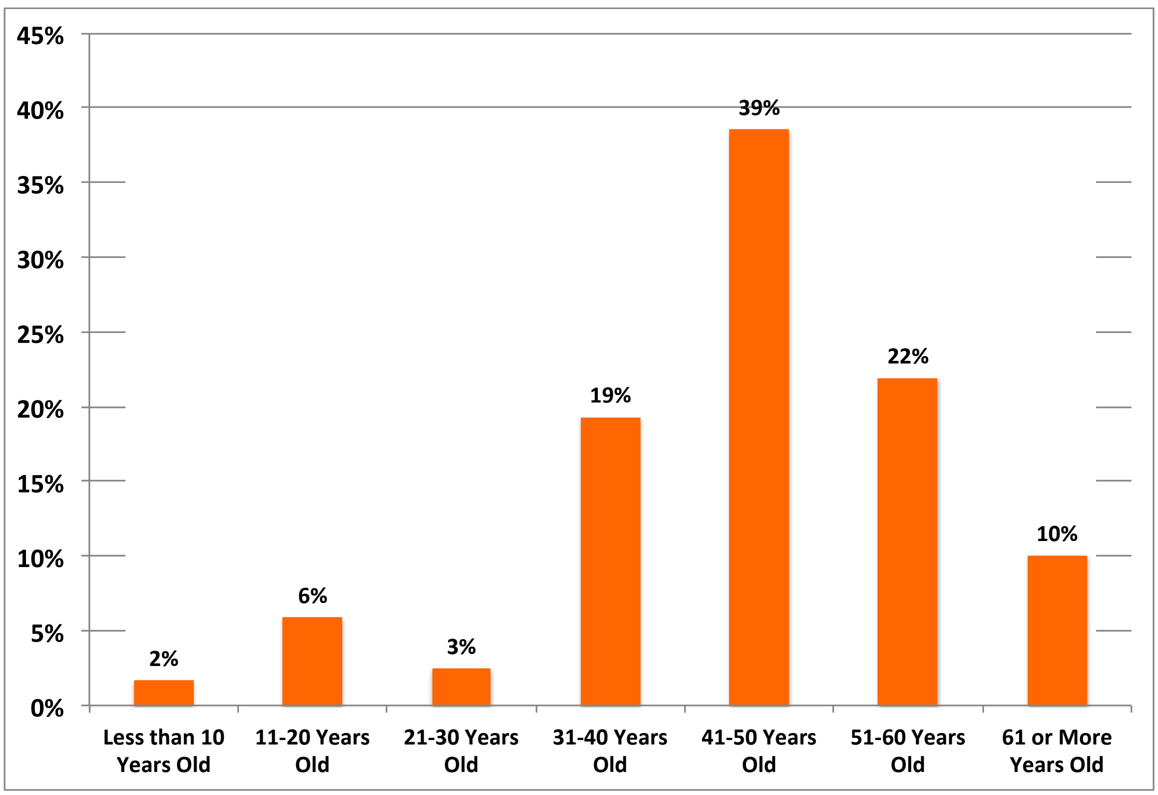
41. Because natural gas prices determine the clearing prices in wholesale energy markets during many hours of the year (i.e., the price that *all* generators receive when they sell power into the market during the hour), energy market prices are expected to remain low for the foreseeable future, as Figure 11 indicates.

[33] Data for this chart derived from SNL Financial.

E. The American Coal Fleet is Aging.

42. The U.S. fleet of coal-fired EGUs is aging. As shown in Figure 13 below, by 2022, more than 70 percent of existing coal-fired capacity (in MW) will be over 40 years old and almost one-third (32 percent) will be over 50 years old.[34] Less than 10 percent of existing U.S. coal-fired capacity will be under 20 years old[35] as few new coal-fired EGU have started operations in the last decade and only one new coal-fired power plant has broken ground in the last seven years.

Fig. 12: Age of the U.S. Coal Fleet in 2022 (as percentage of total MW of existing coal-fired EGU capacity)



[34] Coal plant ages derived from data from SNL Financial.
[35] *Id.*

43. The average age of the coal-fired EGUs that have retired since the beginning of 2010 has been 53 years.[36]

44. The median age of the coal-fired EGUs listed in Exhibit 29 of Seth Schwartz's Declaration and Report is 43 years.[37] The average age of these units is 45 years.[38] By the end of the Clean Power Plan compliance period in 2030, these plants would, on average, be 60 years old if they continue operating.[39]

45. Babcock & Wilcox, an experienced designer and builder of fossil fuel-fired and nuclear EGUs, including coal-fired plants, has identified the consequences of plant aging as follows:

> **"Power Plant Aging**
>
> At the beginning of power plant life there is a period in which the operators and maintenance crews learn to work with the new system and minor problems are resolved. This period may be marked with a high forced outage rate, but this quickly declines as the system is broken in.
>
> As the plant matures, the personnel adapt to the new system, and any shortcomings are overcome or better understood. During this phase the forced outage rate remains low, availability is high, and the operating and maintenance costs are minimal. This mature phase normally lasts 25 to 30 years, depending on the design and use of the unit. The power plant is usually operated near rated capacity during this period.
>
> Following this phase, the aging process becomes noticeable. Forced outages and maintenance costs increase and availability

[36] Data on coal plant retirement ages from SNL Financial.
[37] *See* NMA Stay Motion, Schwartz Decl. and Report, Ex. 29; coal EGU retirement data provided by SNL Financial.
[38] *Id.*
[39] *Id.*

declines. Component end of life usually causes the higher forced outage rate. Occasional operational error and the degradation of boiler components due to erosion, corrosion, creep and fatigue lead to localized failures. The forced outage rate steadily increases during this phase unless major overhauls or component replacements are instituted.[40]

* * * *

Traditional Roles of the Aging Plant

As the aging plant becomes less reliable, its role is often changed. Newer, more reliable plants are less costly to maintain and are generally more efficient to handle the base power load. The older plants become auxiliary units or are designated for peaking service. Older plants with higher heat rates, i.e., lower efficiencies, or with low capacity may be retired. Prior to the 1980s, it was assumed that older plants would be torn down to make room for the newer, larger, more efficient units. It was common to retire a plant after 35 to 40 years of service.

This planned obsolescence began to change in the early 1980s. The cost of newer, more efficient plants became more than most boiler operators could readily finance. As a result new construction was delayed and plans to retire the older plants were put on hold. The need to keep the older units running brought about a new strategy of *life extension*. This is a strategy that delays the plant retirement while maintaining acceptable availability. The strategy requires the replacement of some components to keep the plant running with acceptable forced outage rates and maintenance costs. These replacements or repairs expand upon those traditionally incorporated in a plant maintenance program. Significant capital expenditures are normally required to affect the availability rate."[41]

[40] Babcock & Wilcox, Steam, Its Generation and Use, 40th Edition, (1992), Chapter 46, at 46-1 *et seq.*
[41] *See id.* at 46-1 and 46-2.

46. Therefore, it is reasonable to expect that additional coal-fired EGUs will be retired in coming years due to unfavorable economics resulting from (a) higher annual operating and maintenance costs as they age; (b) the need for additional capital investments as they age; and (c) degradation in their operating performance as they age, in terms of lower net generation and higher planned and forced outage rates. These factors are independent of the Clean Power Plan. In conjunction with the availability and cost of lower cost natural gas and renewable wind and solar resources, these factors will undermine the future viability of existing coal-fired EGUs and will affect when individual coal-fired units will retire.

F. Many Coal-Fired EGUs are Becoming Increasingly Expensive to Operate.

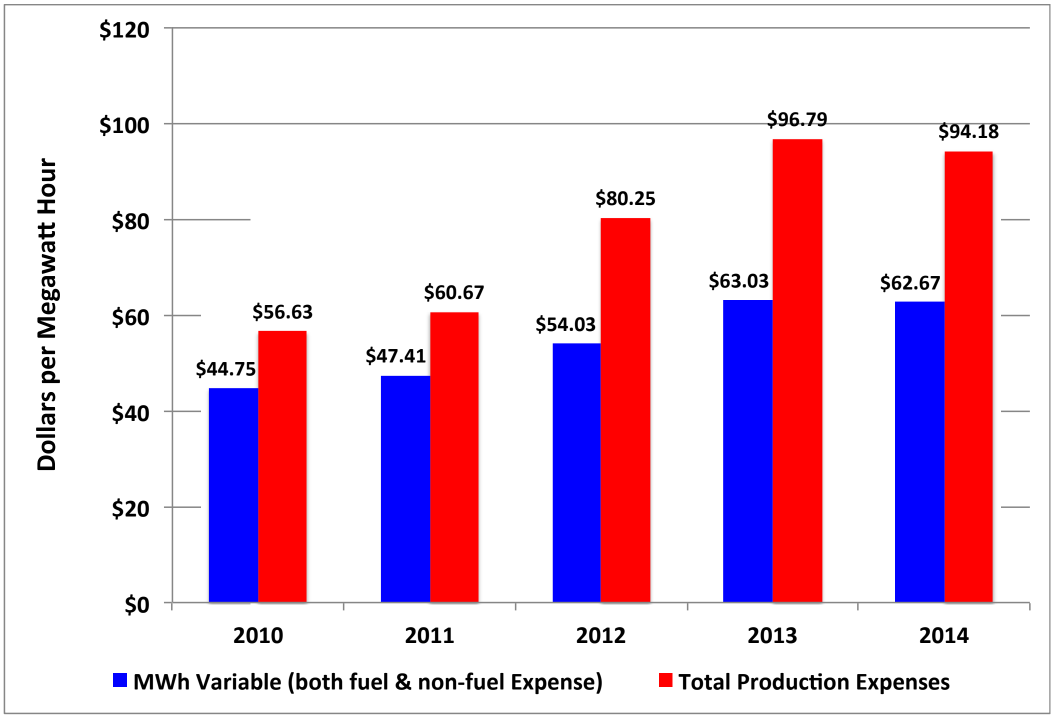
47. The annual per-MWh costs of generating power at coal-fired plants around the U.S. have increased significantly in recent years. In part, this is due to the decline in plant generation discussed earlier in this declaration. However, in large part, the increased cost of producing power at coal plants is due to a substantial increase in those plants' fixed and variable fuel and non-fuel operations and maintenance ("O&M") costs.

48. For example, the cost of generating power at Plant Hammond increased by about two-thirds between 2010 and 2014.[42] This increase was driven in part by a 40 percent increase in the plant's variable fuel and non-

[42] Data derived from Georgia Power Company's FERC Form 1 filings for the years 2010–2014.

fuel O&M expenses.[43] Figure 13 below depicts the recent surge in O&M costs and total production expenses at Plant Hammond.

Fig. 13: The Increasing Cost of Producing Power at Plant Hammond[44]



49. Thus, the average cost of producing a single MWh of power at Plant Hammond increased at a compound annual rate of 13.5 percent for the four-year period.

50. Other examples of the escalation of O&M costs at coal-fired EGUs include the McIntosh Unit 3 coal plant in central Florida, whose O&M costs increased at an annual compound rate of 8 percent between 2009 and 2014,[45] and Colstrip Units 1 and 2 in eastern Montana, whose O&M costs more than

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[43] *Id.*
[44] *Id.*
[45] City of Lakeland, Florida. Department of Electric Utilities, Notes to Financial Statements for the Years 2008-2014.

doubled between 2003 and 2014, a compound increase of almost 7 percent per year.[46]

51. Another example is the Huntley coal-fired EGU in upstate New York. Huntley Power, LLC, the owner of this plant, has said that it is being retired due to current power prices and market conditions in New York State: "it is no longer economical to continue to operate the Facility and . . . it is not expected that it will become economic to operate the Facility [in coming years]."[47] Although Huntley Power has petitioned FERC to approve an interim four-year Reliability Must Run agreement to keep the plant in service, NYISO recently determined that only very minor transmission system upgrades would obviate any potential need to keep the plant online for reliability purposes past a proposed 2016 retirement date.[48] In its submission to FERC, Huntley Power reported that the plant had a gross margin (i.e., total revenues less variable costs) of just $16.4 million for the 12-month period ending July 31, 2015, compared to a total service cost of approximately $80.3 million. In fact, the $16.4 million gross margin was insufficient to cover anything more than 60 percent of the plant's fixed O&M expenses, "let alone any other component of the cost of service."[49]

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[46] Puget Sound Energy FERC Form 1 filings for the years 2003–2014.

[47] Huntley Power LLC, Reliability Must Run Service request to FERC (Oct. 14, 2015), at 4.

[48] Letter from Richard Dewey, Exec. VP, NYISO, to Raj Addepalli, Managing Director, Utility Rates and Service, New York Dep't of Public Service (Oct. 30, 2015), *available at* http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/NY_PSC_Filings/2015/NYISO_PSC_letter_Huntley_2015-10-30_clean.pdf.

[49] *Id.*

52. The annual fixed and variable production expenses exemplified in Figure 13 above do not represent the total cost of producing power at coal-fired EGUs. In addition, plant owners must undertake capital expenditures, or "capex," to upgrade or replace the plant's equipment, structures, and components that have worn down either through use or age. These capex vary from plant-to-plant and year-to-year, but can be quite significant depending on the size and age of the plant and what specific equipment upgrades have been completed. For example, Georgia Power invested over $540 million on capex at Plant Hammond between 2008 and 2014, an average of over $75 million per year.[50]

53. As another example, the owners of the smaller McIntosh Unit 3 invested more than $70 million capex in the plant between October 1, 2008 and September 30, 2014, an average of nearly $12 million in capital costs per year.[51]

54. The already expensive cost of power from existing coal-fired EGUs can be expected to rise even more in the near future. New capex and increased annual O&M expenses will be needed in coming years as a result of plant aging, as discussed in paragraphs 47 through 53 and in cases where inefficient, high-emitting units make upgrades to meet the requirements of EPA rules other than the Clean Power Plan. These additional costs will further reduce these plants' competitiveness. In determining whether to

[50] Georgia Power Company, FERC Form 1 Filings for the years 2008-2014.
[51] City of Lakeland, Florida. Department of Electric Utilities, Notes to Financial Statements for the Years 2008-2014.

upgrade plants to achieve compliance, owners may consider whether the plants will be competitive given the likelihood of a carbon-regulated future. But a decision to close such a plant rather than invest further to comply with current regulations would be a voluntary business decision, not something compelled by the Clean Power Plan.

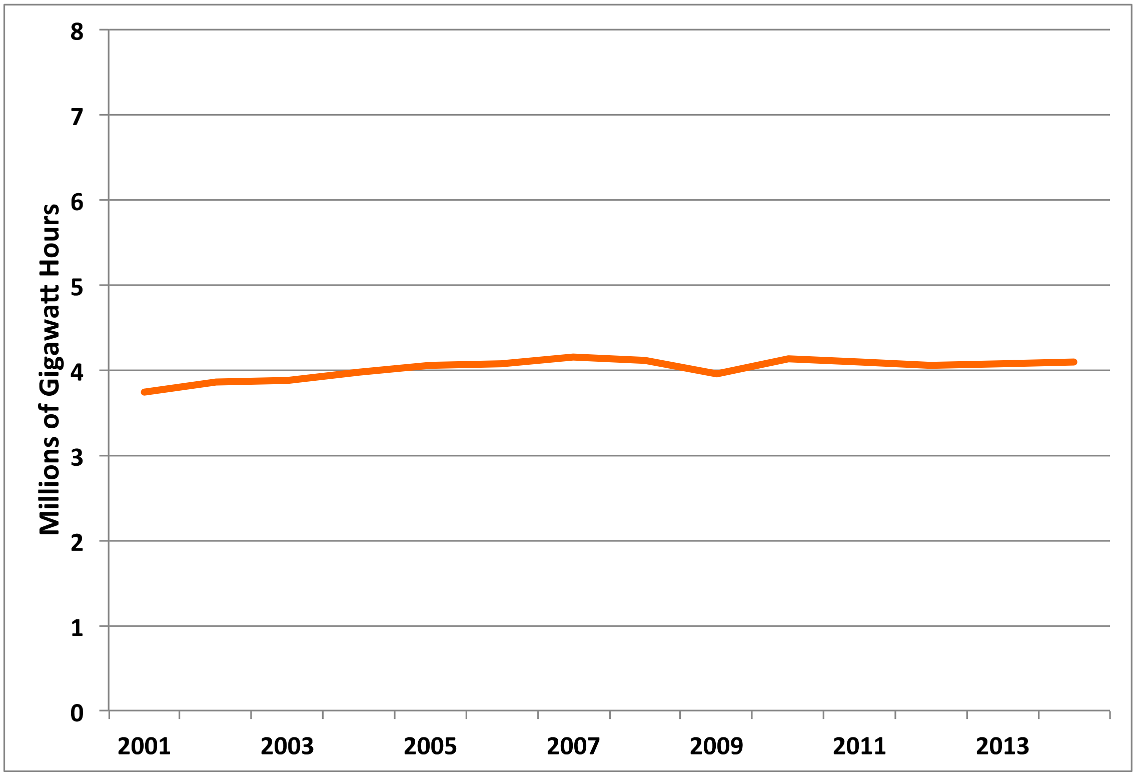
55. All of these added costs will make continued operation of coal-fired EGU more expensive and less economically competitive than natural gas-fired and renewable alternatives. These costs are already increasing and are unrelated to the Clean Power Plan.

G. The Growth in Electric Power Usage Has Slowed Due to Structural Economic Factors and Improved Efficiency.

56. In my opinion, existing coal-fired EGUs cannot depend on future growth in electricity usage as the basis for any significant increases in plant generation and revenues.

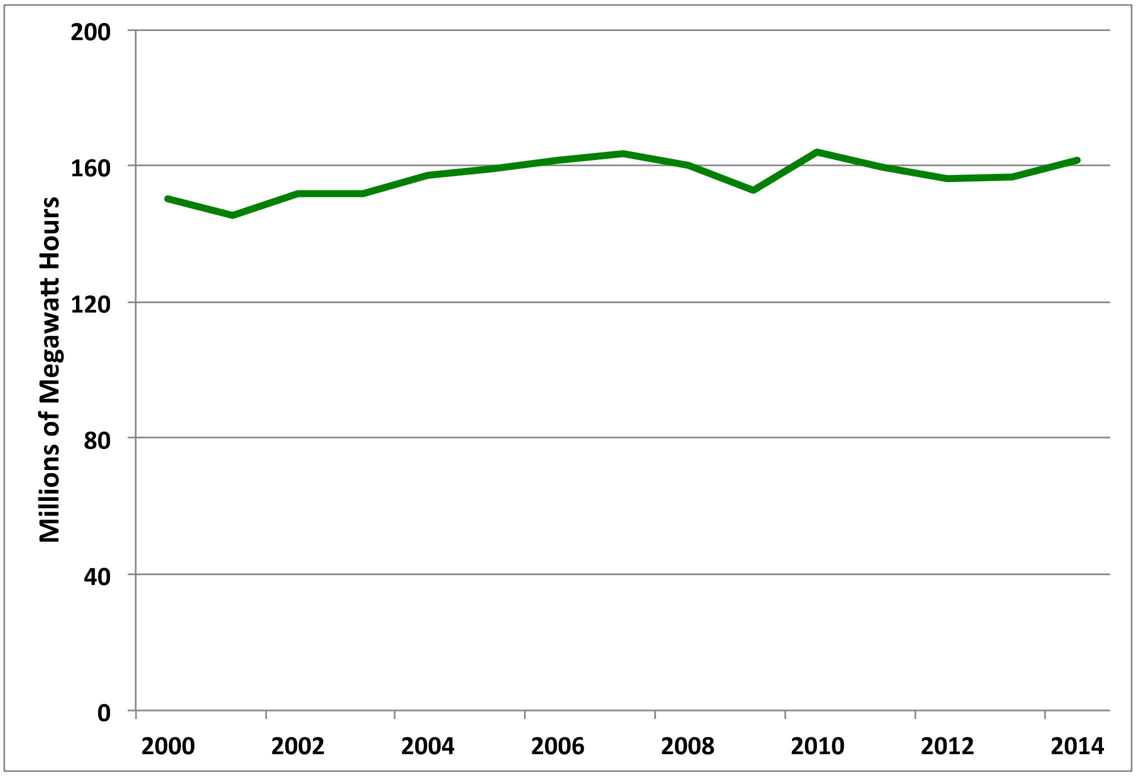
57. As shown in Figures 14a and 14b below, national and regional demands for electric power have been relatively flat for the past ten years, with little growth since 2001.

Fig. 14a: Total U.S. Electric Electricity Usage, 2001-2014[52]



[52] EIA, Table epa_02_02, *available at* http://www.eia.gov/electricity/data.cfm#sales.

Fig. 14b: Southern Company Retail Electric Sales, 2000-2014[53]



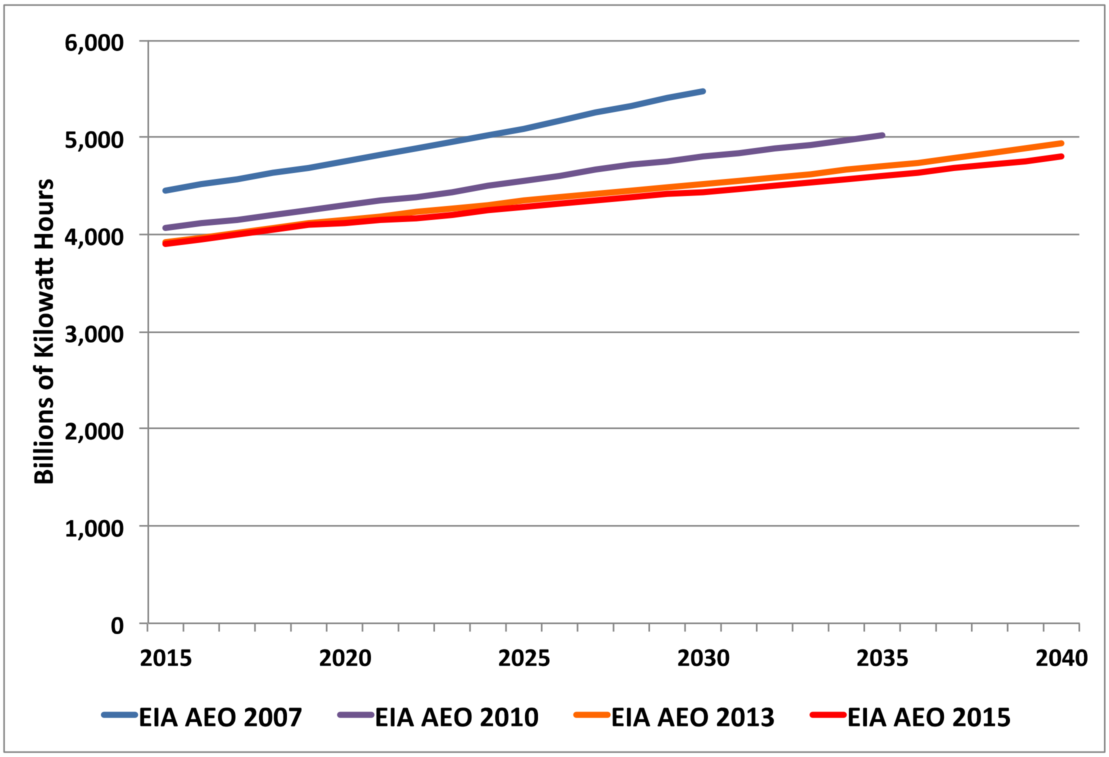
58. At the same time, energy demand forecasts have been declining in recent years as utilities and other load-serving entities reduce their expectations for how much power they will need in coming years.

59. For example, the Energy Information Administration's ("EIA") forecasts of national electric usage have declined dramatically between 2007 and 2015. In fact, as shown in Figure 15, the total electric demand that EIA

[53] *See* Southern Company Form 10-K filings for the years 2000-2014. Southern Company owns approximately 46,000 megawatts of generating capacity and serves 4.4 million customers over 120,000 square miles in Alabama, Florida, Georgia, and Mississippi. *See Out Business: Overview*, http://www.southerncompany.com/about-us/our-business/home.cshtml. Southern's retail sales thus serve as a good proxy for regional load in the southeastern U.S.

predicted in 2007 would be achieved in 2020 will not be experienced until 2040 under EIA's latest projections.

Fig. 15: EIA Forecasts of U.S. Electric Demand from 2007, 2010, 2013, and 2015[54]



60. Investment in energy efficiency savings is a significant reason for this trend. U.S. spending on electric energy efficiency programs exceeded $24 billion in the years 2010-2014 according to the American Council for an Energy-Efficiency Economy ("ACEEE").[55] ACEEE estimates that the total savings from energy efficiency programs totaled approximately 25.7 million

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[54] Chart generated from the files for EIA's *Annual Energy Outlook reports* for the years 2007, 2010, 2013, and 2015, *available at* http://www.eia.gov/forecasts/aeo/ and http://www.eia.gov/forecasts/aeo/archive.cfm.

[55] ACEEE, *2015 State Energy Efficiency Scorecard* (Oct. 2015), at 23, *available at* http://aceee.org/research-report/u1509.

MWh in 2014, a 5.8 percent increase from 2013.[56] Equal or greater annual MWh savings can reasonably be expected in future years as (1) spending on electric efficiency programs typically produces savings in more than a single year, and (2) additional investments are made in energy efficiency as state and federal energy efficiency regulations become more stringent over time.

61. The increasing installation of more distributed rooftop solar PV resources also will keep electric system loads down, as electricity that would otherwise have been provided by the grid will instead be supplied by solar PV capacity located at the load location. This will act to reduce the demand on the system as a whole. In addition, in places with "net metering," these distributed PV resources will contribute excess electricity to the grid part of the time, reducing needs for power from central generating stations.

H. The Financial Value of Domestic U.S. Coal-Fired EGUs Declined Significantly Since 2008.

62. The fundamental market forces and factors I have discussed have led to dramatic declines in the values of many domestic U.S. coal fleets between 2008 and 2013. Figures 16a and 16b, based on an analysis by FitchRatings,[57] display these trends.

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[56] *Id.* at viii.

[57] Fitch Ratings, *The Erosion in Power Plant Valuations* (Sept. 25, 2013), *available at* www.fitchratings.com.

Fig. 16a: Declines in Coal Fleet Valuations (Net Present Value, in Dollars per KW of Capacity in Each Fleet) Between 2008 and 2013[58]

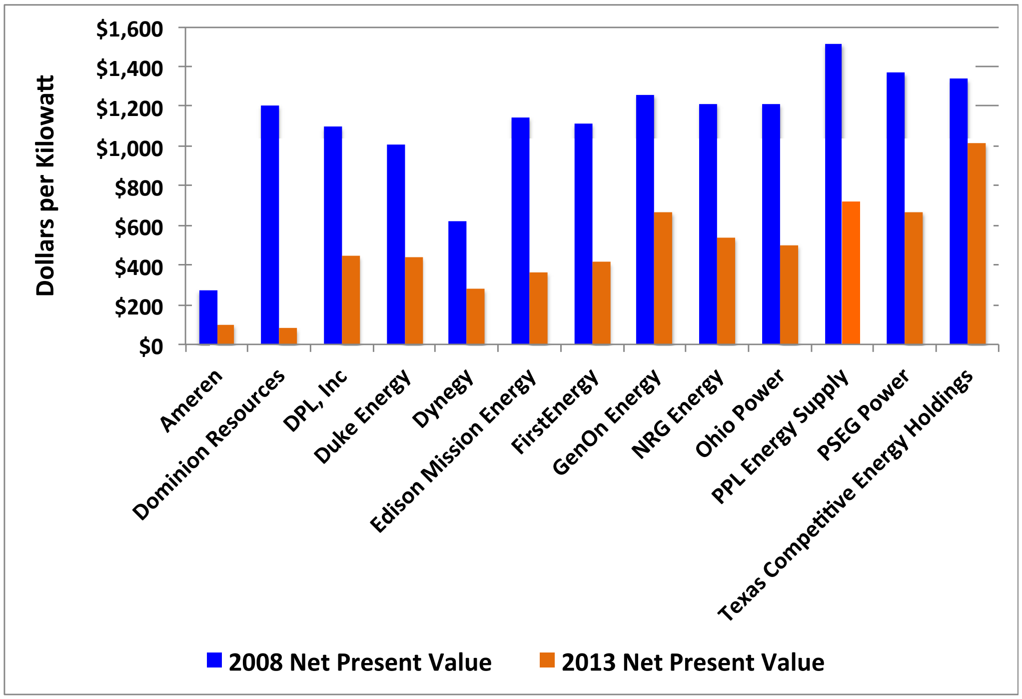
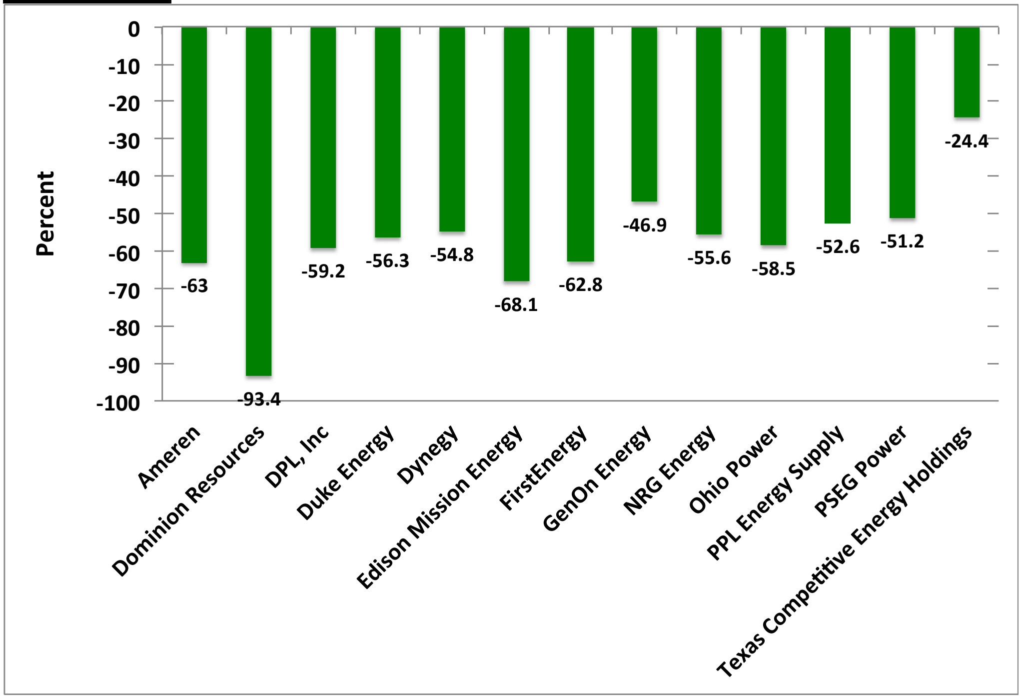


Figure 16b: Percentage Declines in Coal Fleet Valuations Between 2008 and 2013[59]



58 *Id.*
59 *Id.*

63. The market for merchant coal-fired EGUs is deteriorating rapidly. For example, Dynegy bought the Danskammer plant in Newburgh, New York (along with a partial share of the Roseton plant) for $900 million in 2001.[60] When the plant was resold in 2013, its value had plummeted to just $3.5 million.[61] As another example, Dominion Resources sold its 1600 MW Brayton Point coal plant in Southeastern Massachusetts for an estimated $55 million in 2013,[62] shortly after spending $1 billion to complete capital upgrades on the plant.[63] One month after acquiring the plant, the new owner announced a decision to retire Brayton Point in 2017.[64]

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[60] *Central Hudson closes sale on Roseton and Danskammer generating plants*, Power Engineering (Feb. 2, 2001), *available at* http://www.power-eng.com/articles/2001/02/central-hudson-closes-sale-on-roseton-and-danskammer-generating-plants.html.

[61] *Dynegy Announces Results of Roseton and Danskammer Auction*, BusinessWire (Dec. 10, 2012), *available at* http://www.businesswire.com/news/home/20121210006337/en/Dynegy-Announces-Results-Roseton-Danskammer-Auction.

[62] Joe C. Goode, *Somerset's Brayton Point power station sold to private equity firm*, The Herald News (Mar. 11, 2013), *available at* http://www.heraldnews.com/article/20130311/NEWS/303119890. Brayton Point was sold in a package deal with two other power plants that was projected to result in after-tax proceeds of approximately $650 million. Although Dominion did not publicize the specific sale price of Brayton Point, analysts have estimated its value to have been approximately $55 million at the time of the sale. *See* Institute for Energy Economics and Financial Analysis, Press Release, *Connecticut's Last Coal-Fired Power Plant Is in Critical Financial Condition, Community Needs to Plan for Transition* (Jan. 23, 2014), *available at* http://ieefa.org/press-release-connecticuts-last-coal-fired-power-plant-is-in-critical-financial-condition-community-needs-to-plan-for-transition/.

[63] *See* Steve Urbon, *Brayton Point to shut down as of June 2017*, South Coast Today (discussing capital expenditures at Brayton Point) (Oct. 7, 2013), *available at* http://www.southcoasttoday.com/article/20131007/NEWS/131009917.

[64] Alex Kuffner, *New owners to shutter outmoded Brayton Point Power Station in 2017*, Providence Journal (Oct. 8, 2013), *available at* http://www.providencejournal.com/article/20131008/News/310089995.

I. Petitioners Misrepresent the Coal-Fired EGUs that Would Have to Retire in the Short-Term Due to the Clean Power Plan.

64. Given the factors that I have discussed, large numbers of additional coal-fired EGUs are likely to be retired in the coming years irrespective of the Clean Power Plan. As an illustration of the impact of the market forces and economic trends I have discussed thus far, between the beginning of 2009 and March, 2014—before the Clean Power Plan was even proposed, let alone finalized—more than 22 GW of coal-fired EGU capacity were retired and another 27 GW were announced for retirement.[65] In addition to outright retirements and announcements, an additional 11 GW of coal-fired EGU capacity was being targeted for conversion to burn other fuels, primarily natural gas.[66]

65. In claiming that numerous specific units will be forced to retire imminently due to the Clean Power Plan, petitioners not only misuse EPA's IPM modeling (*see* Burtraw Declaration ¶¶ 16–27) and ignore the Clean Power Plan's extended schedule and flexible compliance options (*see* Tierney declaration ¶¶ 39–44, 48–56), they also misrepresent the circumstances surrounding those plants and the reasons that many of them are uneconomical.

66. For example, in his declaration, Robert Frenzel of Luminant asserts that "EPA's IPM modeling shows Monticello Units 1 and 2 as completely

[65] Data on coal plant retirements and announcements derived from SNL Financial.
[66] *Id.*

shut down in 2016 under all cases."[67] The Chamber of Commerce has also submitted a number of declarations discussing social and economic consequences of retiring Monticello Units 1 and 2.[68] These assertions are misleading. In fact, these two Monticello units were not included in either the IPM "base case" (discussed more below) or the two modeling runs.[69] The agency's modeling therefore says nothing about how the Clean Power Plan may or may not affect Monticello 1 and 2.

67. If Monticello 1 and 2 do retire in the near future, it will be due to factors that have nothing to do with the Clean Power Plan. In 2012, Luminant determined that these two units could no longer compete in the marketplace as year-round generators and requested that they be seasonally idled starting in December of that year.[70] As a Luminant spokesperson explained, "[w]ith power prices very low, those two units are not economical to run during these low demand seasons."[71]

68. Luminant has been heavily dependent on coal-fired generation for many years, having bet extensively on high gas and clean energy prices in

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[67] UARG Stay Petition, Frenzel Decl. ¶ 40.
[68] *See generally* Chamber of Commerce Stay Petition, Declarations of Blanton, Smith, Kennedy, and Witherspoon.
[69] EPA, *EPA Base Case v.5.15 Using IPM— Incremental Documentation* (Aug. 2015), at Table 4-36: Capacity Not Included Due to Recent Announcements (listing Monticello Units 1 and 2 as excluded from modeling), *available at* http://www2.epa.gov/sites/production/files/2015-08/documents/epa_base_case_v.5.15_incremental_documentation_august_2015.pdf.
[70] Terrence Henry, *Luminant Coal Units Get Permission to Mothball This Winter*, State Impact (Oct. 31, 2012), *available at* https://stateimpact.npr.org/texas/2012/10/31/luminant-coal-units-get-go-ahead-to-mothball-this-winter/.
[71] *Id.*

making its strategic investment decisions.[72] On April 29, 2014 the parent company of Luminant, Energy Future Holdings, conceded it had lost that bet and filed for bankruptcy because of low power prices making its coal fleet uneconomic.[73] This is one of the largest bankruptcies in U.S. history.[74]

69. Coal-fired EGUs in Texas like Monticello 1 and 2 are struggling to compete with other, cheaper sources of electricity. For example, wind power has become so plentiful in ERCOT that on September 20 of this year, the spot price of electricity fell below $0/MWh for a period, hitting negative $8.52 per megawatt hour at its lowest point.[75] ERCOT also predicts a massive expansion in Texas's solar industry in the coming years, forecasting a 50-fold increase in generation capacity by 2030 even in under a "business as usual" projection.[76] Indeed, in announcing Luminant's purchase of a 116-

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[72] Ken Silverstein, *Big gamble felled Energy Future Holdings. Safe bet could resuscitate it*, The Christian Science Monitor (May 2, 2014) ("'It teaches a lesson, which is using debt to make a bet on gas prices is unwise,' says Bob Bellemare, chief operating officer of consulting firm Mykrobel in New Mexico, in an interview. 'They bet and they lost and this is the aftermath.'"), *available at* http://www.csmonitor.com/Environment/Energy-Voices/2014/0502/Big-gamble-felled-Energy-Future-Holdings.-Safe-bet-could-resuscitate-it

[73] Energy Future Holdings, Restructuring: Information for TXU Energy Customers, https://www.energyfutureholdings.com/restructuring/information-for-txu-energy-customers/ (last visited Dec. 6, 2015).

[74] Jim Malewitz, *Massive Bankruptcy Tests Texas Utility Regulators*, The Texas Tribune (Aug. 28, 2015), available at http://www.texastribune.org/2015/08/28/mammoth-bankruptcy-deal-looms-texas-utility-regula/.

[75] Robert Walton, *Record wind generation pushes ERCOT prices into negative territory*, Utility Dive (Sept. 15, 2015), *available at* http://www.utilitydive.com/news/record-wind-generation-pushes-ercot-prices-into-negative-territory/405606/; Samantha Solomon, *Want Free Electricity? Move to Texas*, Wall St Daily (Sept. 29, 2015), *available at* http://www.wallstreetdaily.com/2015/09/29/texas-negative-energy-prices/.

[76] Christian Roselund, *Texas grid operator predicts 50-fold increase in solar by 2030*, PV Magazine (Oct. 16, 2015), *available at* http://www.pv-

MW solar facility last September, Luminant CEO Mac MacFarland stated that "solar generation costs have become increasingly competitive."[77]

70. Monticello 1 and 2 are now over 40 years old. They are already uneconomical due to market forces, and because they lack modern pollution control technology, they will likely require substantial capital investments in the near future—potentially on the order of hundreds of millions of dollars—in order to remain online. Notably, when the Titus County Appraisal Review Board recently appraised the entire Monticello plant (including Unit 3) at $341 million for tax purposes, Luminant argued for an appraisal of just $50 million.[78] Luminant's own valuation of Monticello indicates that major capital investments at Units 1 and 2 would not be an economically sensible decision, and that near-term retirement would be the most rational course of action for those units.

71. Given that Monticello 1 and 2 are already uneconomical and outdated, petitioners have no support for their claims that the Clean Power Plan will cause the closure of those units at any point before or during the compliance period. They may retire in the near future, but it will be for reasons other than the Clean Power Plan.

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magazine.com/news/details/beitrag/texas-grid-operator-predicts-50-fold-increase-in-solar-by-2030_100021587/.

[77] Luminant, Press Release, *Luminant Solar Project Expands Diverse Mix of Generation* (Sept. 8, 2015), https://www.luminant.com/luminant-solar-project-expands-diverse-mix-of-generation-2/#.VlPXe3arS70.

[78] Marcia Davis, *Board stands ground on plant appraisal*, The Daily Tribune (July 1, 2015), *available at* http://www.dailytribune.net/news/board-stands-ground-on-plant-appraisal/article_4808f3fa-2041-11e5-9ec6-fbbde6d434de.html.

72. Another example of inaccurate or misleading testimony from petitioners is NorthWestern Energy's ("NWE") declaration. NWE's representatives claim that all four coal-fired units at Colstrip Generating Station in Montana will be forced into "premature retirement" due to the Clean Power Plan.[79] Specifically, they assert that, "[t]o achieve compliance under a rate-based program, Colstrip must cease operation in 2022."[80] However, the claim that all four units at Colstrip will close "prematurely" as a result of the Clean Power Plan is simply not credible. Units 1 and 2 are under substantial economic pressure and are likely to retire for reasons unrelated to the Clean Power Plan—a 2022 retirement date would not be premature in any event. Furthermore, there is no basis to the claim that Colstrip 3 and 4 will be forced to retire in 2022 due to the Clean Power Plan.

73. Even if it were true that the Clean Power Plan would require one or more of the Colstrip units to retire in 2022, this would not represent immediate, irreparable harm, and therefore no stay is warranted. Furthermore, NWE ignores the fact that state implementation plans under the Clean Power Plan may permit trading of credits or allowances for compliance. Without knowing what those markets will look like and what the prices of those allowances will be, NWE cannot credibly argue that retirement in 2022 is the only compliance option for Colstrip.

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[79] NWE Stay Motion, Hines and Cashell Decl. ¶ 44.
[80] *Id.*

74. A decision to retire Units 1 and 2 in 2022 or sooner would not be premature. These units came online in 1975 and 1976 and were designed to operate for just 30 years, as discussed in Colstrip's original Environmental Impact Statement under Montana state law.[81] Forty years later, Colstrip 1 and 2 are now subject to significant cost pressure from cheaper generation resources, like purchased electricity from the wholesale Mid-Columbia Hub or wind power. To cite one pertinent example, NWE's own reports show that the company's Judith Gap wind farm generated electricity at less than half the rate of Colstrip from 2009 through 2015.[82] In fact, an analysis I authored showed that continued operation of Colstrip 1 and 2 would not be profitable for the owners of Talen Energy (a merchant company which owns 50 percent of the two units), nor would it be economical for the customers of Puget Sound Energy (which owns the other 50 percent of Colstrip 1 and 2).[83]

75. Colstrip is facing increased pressure to comply with environmental regulations other than the Clean Power Plan. While modern, state-of-the-art plants incorporate pollution controls into their design, aging and outdated units like Colstrip 1 and 2 often require retrofits to avoid polluting above

[81] Montana Dep't of Health and Environmental Sciences, Environmental Impact Statement on the Proposed Montana Power Company Electrical Generating Plant at Colstrip, Montana (Mar. 1973), at iii.

[82] Jason T. Brown, Montana Public Service Comm'n, *NorthWestern Energy Residential Electric Rates and Electricity Supply (Through June 2014)*, at 9, *available at* http://www.mtaffordableelectricity.org/wp-content/uploads/2015/10/2014-NWE-Electric-Rate-Graphs.pdf.

[83] David Schlissel and Cathy Kunkel, IEEFA, *A Bleak Future for Colstrip Units 1 and 2* (June 2015), *available at* http://ieefa.org/wp-content/uploads/2015/06/A-BLEAK-FUTURE-FOR-COLSTRIP-UNITS-1-AND-2.pdf.

legal limits. Such investments may not make economic sense for older units that are already unprofitable. For instance, Colstrip is expected to face investment decisions to comply with the recently-finalized coal ash rule that, for the first time, requires power plants to appropriately handle dangerous coal ash.[84] In addition, three of the four Colstrip units are the subject of a citizen suit action asserting multiple violations of the Prevention of Significant Deterioration program.[85] That lawsuit is scheduled to go to trial in 2016. These factors are further evidence that, unlike cleaner and cheaper sources of electricity, coal-fired EGUs such as Colstrip are facing a constellation of economic forces separate from the CPP that render them less competitive with each passing year.

76. In fact, NWE itself, which owns a share in Unit 4, apparently believes that Units 1 and 2 have zero—or even negative—value. In January 2013, NWE offered to buy all of the assets of another generator, PPL Corporation, including PPL's interest in Units 1, 2, and 3. NWE submitted two bids to PPL, offering $400 million for *all* of PPL's assets (including PPL's share of the Colstrip units), and one for $740 million for *only* PPL's hydropower units.[86] In other words, NWE considered Colstrip Units 1, 2, and 3 to have a

[84] *See* Montana Dep't of Envtl. Quality, *Colstrip Update* (Oct. 2015), at 3, *available at* http://www.deq.mt.gov/MFS/ColstripSteamElectricStation/Colstrip%20deq/Colstrip/FactSheetOct2015.pdf.

[85] *Sierra Club v. PPL Montana LLC,* Dkt. No,. 13-cv-00032 (D. Mont. Mar. 6, 2013), *available at* http://www.scribd.com/doc/129002674/13-3-6-Filed-Complaint.

[86] NWE, Application for Approval to Purchase and Operate PPL Montana's Hydroelectric Facilities, for Approval of Inclusion of Generation Asset Cost of Service in Electricity Supply Rates, for Approval of Issuance of Securities to Complete the Purchase, and for Related Relief, Docket No. D2013.12.85, before the Montana Public Service Comm'n

negative value of approximately $340 million. NWE ultimately purchased PPL's hydropower assets but not its interests in Colstrip Units 1, 2, and 3.

77. A merchant company, Talen Energy, later acquired PPL's entire share of Colstrip. The declining value of these assets is apparent from the fact that PPL had been writing off Units 1 and 2 in recent years prior to their sale, as well as writing down their total taxable value since 2013 by 67 percent.[87] The taxes Talen pays to state and local governments on these units have likewise declined significantly in recent years.[88] If Colstrip 1 and 2 do close in 2022, it will be due to factors that predate, and are unrelated to, the Clean Power Plan.

78. As for Units 3 and 4, NWE merely asserts that they would retire in 2022 under a rate-based CPP program. However, under the CPP's mass-based compliance pathway, Montana's average annual emissions goal for the years 2022-2024 is 13,776,601 tons of CO_2 per year. As indicated above, Colstrip 1 and 2 may well retire for reasons unrelated to the CPP before 2022—indeed, policymakers in Washington State and Montana are already exploring this option.[89] Furthermore, Montana's J.E. Corette coal

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(Dec. 2013), at BBB-7, *available at* http://www.northwesternenergy.com/docs/default-source/documents/hydro/application/docket-no-d2013-12-85-approval-to-purchase-hydro-e-file.pdf.

[87] Montana Dep't of Revenue, Memorandum from Rose Bender to Director Kadas Re: Colstrip Units 1 and 2 Analysis (Sept. 1, 2015), at 2.

[88] *Id.*

[89] *Officials discuss future of Colstrip power plants*, Billings Gazette/Associated Press (Oct. 28, 2015), *available at* http://billingsgazette.com/news/state-and-regional/montana/officials-discuss-future-of-colstrip-power-plants/article_71b52592-f025-5bc2-9cc2-88bcdab875f0.html; *see also* Mike Dennison, *Washington state may play critical role in future of Colstrip power plants*, KRTV.com (Dec. 4, 2015), *available at*

plant shut down permanently in August 2015.[90] According to EPA's data, the state's remaining regulated units (including Colstrip 3 and 4) emitted 13,713,208 tons of CO_2 in 2012. If Colstrip 1 and 2 do indeed retire by 2022, the state's EGUs can therefore operate at historical levels through 2024 and satisfy Montana's Clean Power Plan goals; no other compliance measures would be needed. There is no basis to the assertion that the Clean Power Plan will force the near-term retirement of Colstrip 3 and 4.

79. Given its unreliable operating history, it is also plausible that Unit 4 will not run at full capacity for significant stretches of time during the compliance period. In the last six years, this unit was not operating for approximately 12 months because of two extended, unplanned outages.[91] The President and CEO of Talen Energy has made clear that the company has no plans at this time to make the investments needed to avoid some plant outages in the future: "We've seen a few unplanned outages at Colstrip

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http://www.krtv.com/story/30671627/washington-state-may-play-critical-role-in-future-of-colstrip-power-plants.

[90] Tom Lutey, *Crews begin dismantling J.E. Corette power plant*, Billings Gazette (Aug. 3, 2015), *available at* http://billingsgazette.com/news/local/crews-begin-dismantling-j-e-corette-power-plant/article_53bd0a75-59c3-54a7-b2f7-084d751cadcd.html.

[91] *Wash. Util. and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dkt. Nos. UE-111048 and UG-111049 before the Wash. Utils. and Transp. Comm'n, Prefiled Direct Testimony (Confidential) of Michael L. Jones on Behalf of Puget Sound Energy, Inc.- Redacted Version (June 13, 2011) at 5:14—6:10 (discussing five-month forced outage in 2009), *available at* http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/fb14b4e61387a425882578af005ff244; Mike Dennison, *PSC deciding who should pay costs of Colstrip plant outage* , KPAX News (Oct. 6, 2015) (describing seven-month outage in 2013-14), *available at* http://www.kpax.com/story/30200756/psc-deciding-whether-nw-energy-or-consumers-should-pay-costs-of-colstrip-plant-outage.

primarily for boiler tube leaks, but market price signals in the West don't support proactively putting capital into the units at this time."[92]

80. Another example of misleading testimony is the declaration submitted by representatives of Alabama Power Company. This declaration asserts that the company will be required to prematurely shutter more than 2,600 MW of its fossil fuel-fired generating capacity under the Clean Power Plan, leading to negative impacts on reserves, transmission, fuel contracts, and property tax revenues.[93] These claims are disingenuous. Of the 14 units the Alabama Power declaration claims will retire due to the Clean Power Plan, ten will convert or have already converted to natural gas on account of decisions made prior to the rule's finalization, while the other four are shown to retire in 2016 regardless of the Clean Power Plan, under EPA's base case (i.e., "business as usual") modeling run.

81. Before the Clean Power Plan was proposed, Alabama Power decided to convert six of the units discussed in the declaration (Gaston Units 1–4 and Gadsden Units 1–2) to natural gas; these conversions will occur by 2016.[94] In addition, under an August 2015 settlement agreement with EPA pursuant to a Clean Air Act lawsuit against the company, Alabama Power agreed to burn only natural gas at Barry Units 1 and 2 no later than October 23, 2015

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[92] Talen Energ Corp., edited transcript of Talen Energy earnings conference call for Q3, 2015 (Nov, 5, 2015), *available at* https://beta.finance.yahoo.com/news/edited-transcript-tln-earnings-conference-180852200.html?ltr=1.

[93] *See* UARG Stay Motion, Heilbron Decl.

[94] *Eye on EPA, Alabama Power to convert four coal units to gas,* Electric Power Daily, Platts (Apr. 25, 2012).

and at Greene County Units 1 and 2 no later than January 1, 2017.[95] In fact, Barry Units 1 and 2 already ceased burning coal in April 2015 and will remain available on a limited basis with natural gas as the fuel source.[96] Furthermore, Mississippi Power (like Alabama Power, a subsidiary of Southern Company and part owner of these units) already agreed to cease burning coal at Green County Units 1 and 2 by April 2016 pursuant to a settlement agreement with Sierra Club negotiated in August 2014.[97]

82. As for the remaining units cited in its declaration—Gorgas units 8, 9, and 10 and Barry Unit 4—Alabama Power fails to mention that EPA's IPM modeling shows these units as retiring in 2016 under what is called a "base-case scenario."[98] In the IPM platform, a "base case" simply models what would occur in the power market in the absence of the regulation being analyzed (in this case, the CPP) (*see* Burtraw Decl. ¶¶ 28–35). Because Gorgas 8–10 and Barry 4 retire under its base-case scenario, Alabama Power's declarant is wrong to state that the model represents these units as retiring in 2016 because of the CPP—on the contrary, it shows them as retiring *anyway* in that year, regardless of EPA's rule.

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[95] *United States v. Alabama Envtl. Council*, Order Modifying Consent Decree at 8-9, No. 2:01-cv-00152-VEH, ECF No. 400 (N.D. Ala. Aug. 24, 2015); *see also* Dennis Pillion, *Alabama Power agrees to shutter 3 coal-fired units, convert 4 others to natural gas in EPA deal*, AL.com (June 25, 2015).

[96] *See* Alabama Power Company, SEC Form 10-Q, filed Nov. 5, 2015, at 27.

[97] *Id.; see also* Jack Elliott Jr., *Mississippi Power And Sierra Club Settle Litigation Over Coal Plant Construction*, Associated Press (Aug. 4, 2014), http://www.huffingtonpost.com/2014/08/04/mississippi-power-sierra-club-litigation_n_5648349.html.

[98] *See* Schwartz Decl., *supra* n. 37, Ex. 31 (listing base-case retirement year as 2016 for Gorgas 8-10 and Barry 4).

83. Table 1 below summarizes the status and generation capacity of the units discussed in Alabama Power's declaration.

Table 1: Status of Alabama Power Coal Plants Discussed in Declaration

Unit	Capacity (MW)	2014 Capacity Factor[99]	Actual Status
Barry 1	138	1.6	Ceased burning coal in April 2015, will remain available on a limited basis with natural gas as the fuel source.
Barry 2	137	1.5	Ceased burning coal in April 2015, will remain available on a limited basis with natural gas as the fuel source.
Barry 4	362	43.4	Retires under EPA's base-case scenario.
Greene County 1	254	54.5	Required to cease burning coal by April 2016; must operate solely on natural gas thereafter.
Greene County 2	243	72.6	Required to cease burning coal by April 2016; must operate solely on natural gas thereafter.
Gorgas 8	161	35.8	Retires under EPA's base-case scenario.
Gorgas 9	170	26.8	Retires under EPA's base-case scenario.
Gorgas 10	703	69.2	Retires under EPA's base-case scenario.
Gadsden 1	64	25.7	Converting to natural gas.
Gadsden 2	66	12.6	Converting to natural gas.
Gaston 1	254	22.2	Converting to natural gas.
Gaston 2	256	19.1	Converting to natural gas.
Gaston 3	254	31.9	Converting to natural gas.
Gaston 4	256	42.5	Converting to natural gas.

[99] Capacity factor was calculated using summer capacity (MW) data and net generation (MWh) data from Form-EIA 860 and Form-EIA 923 for the year 2014.

84. Many of the remaining units that petitioners' declarants claim will be affected by the Clean Power Plan are likely to face serious economic pressure in the near term for specific reasons other than the Clean Power Plan; some have already succumbed to that pressure. For example:

- Plant Watson (discussed in the Reaves[100] declaration): Mississippi Power announced in 2014 that it would cease burning coal at Watson Units 4 and 5 by April 2015,[101] well before the final Clean Power Plan was issued.

- Naughton Power Plant (discussed in the Schwartz[102] and Cottrell[103] declarations): Naughton Unit 3 is expected to convert to natural gas in 2018;[104]

- Conesville Power Plant (discussed in the Schwartz[105] and Cottrell[106] declarations): Conesville is now so uneconomical to operate that its owner, AEP, is seeking approval from the Ohio Public Utilities Commission for a bailout package for this and other coal plants.[107]

- Laramie River Station (discussed in the Raatz[108] declaration): This high-emitting facility is expected to need investment in pollution

[100] UARG Stay Motion, Reaves Decl. ¶ 13.
[101] *Final coal barge arrives at Plant Watson*, Hattiesburg American (Feb. 25, 2015), *available at* http://www.hattiesburgamerican.com/story/news/2015/02/25/final-coal-barge-arrives-at-plant-watson/24015347/.
[102] Schwartz Decl., *supra* n. 37, ¶ 38.
[103] NMA Stay Motion, Cottrell Decl. ¶ 9.
[104] Pacific Power, Press Release, PacifiCorp Long Range Energy Plan Calls for Less Coal, More Energy Efficiency (June 08, 2015), *available at* https://www.pacificpower.net/about/nr/nr2015/irp-energy-plan.html.
[105] Schwartz Decl., *supra* n. 37, ¶ 38.
[106] Cottrell Decl., *supra* n. 103, ¶ 8.
[107] Cathy Kunkel, IEEFA, *Briefing Note: West Virginia Bailout Emboldens FirstEnergy and AEP in Ohio* (Oct. 2015), at 3–4, 7–8, *available at* http://ieefa.org/wp-content/uploads/2015/10/West-Virginia-Bailout-Emboldens-FirstEnergy-and-AEP-in-Ohio-October-2015.pdf.
[108] Stay Motion of Basin Electric Power Cooperative, Raatz Decl. ¶ 21.

controls to comply with EPA's anticipated Regional Haze FIP for Wyoming.[109]

- Bonanza Power Plant (discussed in Rasmussen[110] declaration): As part of a proposed settlement agreement with EPA and environmental groups that is now open for public comment, Deseret Electric Power Cooperative would have to install pollution controls at Bonanza and limit that unit's coal consumption, which may result in early retirement.[111]

- Mill Creek Generating Station (discussed in Murray[112] declaration): This plant is currently the subject of a citizen lawsuit for violations of the Clean Air Act,[113] and Mill Creek Unit 1 will soon face compliance obligations under EPA's 316(b) rule regulating cooling water intake structures.[114]

- Plant Hammond (discussed in Pemberton[115] declaration): As noted previously, Hammond is already struggling to compete financially and will likely have to install cooling towers as part of a recent settlement agreement.

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[109] Basin Electric Power Cooperative, Press Release, Parallel paths will determine Laramie River's future (June 13, 2014), *available at* http://www.basinelectric.com/News-Center/News-Articles/News-Briefs/parallel-paths-will-determine-laramie-rivers-future.html.

[110] UARG Stay Motion, Rasmussen Decl. ¶¶ 6–10.

[111] Robert Walton, *Settlement could spell early retirement for Utah coal plant*, Utility Dive (Oct. 8, 2015), *available at* http://www.utilitydive.com/news/settlement-could-spell-early-retirement-for-utah-coal-plant/406974/; *see also* 80 Fed. Reg. 63,993 (Oct. 22, 2015) (requesting public comment on terms of settlement agreement).

[112] NMA Stay Motion, Murray Decl. ¶ 38.

[113] *Sierra Club v. Louisville Gas and Electric Co.*, Civil Action No. 3:14-CV-391-DJH., Complaint, Dkt. No. 1 (W.D. Ky. May 28, 2014), *available at* http://www.kentucky.com/news/article43398099.ece/BINARY/Mill%20Creek%20complaint.

[114] PPL, et al., SEC Form 10-Q for the Quarterly Period Ended March 31, 2015 (filed May 7, 015), *available at* http://www.streetinsider.com/dr/news.php?id=10534388.

[115] UARG Stay Motion, Pemberton Decl. ¶ 13.

85. As these examples show, petitioners' declarants tell a story of coal-fired generation throughout the country that does not stand up to the facts. These units are already retiring or re-powering to other fuel sources, and are doing so because of factors other than the Clean Power Plan.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed this 7th day of December, 2015

David Schlissel

Biography of David A. Schlissel
Director of Resource Planning Analysis
Institute for Energy Economics and Financial Analysis

David Schlissel is the Director of Resource Planning Analysis for the Institute for Energy Economics and Financial Analysis. He has served as a consultant, expert witness, and attorney since 1974 on financial, economic and engineering issues in the fields of energy and the environment. This work has involved preparing financial and economic analyses, conducting technical investigations and drafting reports and expert testimony.

Mr. Schlissel's work in recent years has focused in large part on preparing analyses of the following: the financial viability of retrofitting versus retiring operating power plants; wholesale energy and capacity market prices; the relative economics of renewable resources; the risks associated with investments in proposed fossil-fired power plants and their alternatives; electric grid reliability; and the evaluation of utility resource plans.

Mr. Schlissel's clients have included state utility regulatory commissions in Arkansas, Kansas, New Mexico, Arizona, Maine and California, publicly-owned utilities, non-utility generators, power plant equipment suppliers, state attorneys general and consumer advocates and environmental groups. He has presented testimony on issues related to electric utilities in more than 165 cases before regulatory boards and commissions in 38 states, two federal regulatory agencies, and in state and federal court proceedings. He also was the lead author for a number of reports including *When, Not If: Bridgeport's Future and the Closing of PSEG's Coal Plant; Mountain State Maneuver, AEP and FirstEnergy Try to Stick Ratepayers with Risky Coal Plants; Public Utility Regulation without the Public: The Alabama Public Service Commission and Alabama* Power; *Dark Days Ahead: Financial Factors Cloud the Future Profitability at Dominion Resource's Brayton Point Power Plant*; and *Don't Get Burned: The Risks of Investing in New Coal Plants.*

Mr. Schlissel holds BS and MS degrees in Astronautical Engineering from the Massachusetts Institute of Technology and Stanford University. He also received a Juris Doctor degree from Stanford University School of Law. In addition, he studied Nuclear Engineering and Project Management at MIT.

Copies of Mr. Schlissel's public reports, presentations and expert testimony are available at www.ieefa.org and www.schlissel-technical.com.